# CLASS VI SEMI-ANNUAL REPORT
# 40 CFR 146.91(a)

## Illinois Industrial Carbon Capture and Storage Project

### INSTRUCTIONS

This template provides an outline and recommendations for the Semi-Annual Reports.

In this template, examples or suggestions appear in **blue text**. These are provided as general recommendations to assist with site- and project-specific document development. The recommendations are not required elements of the Class VI Rule. This document does not substitute for those provisions or regulations, nor is it a regulation itself, and it does not impose legally-binding requirements on the EPA, states, or the regulated community.

Please delete the **blue text** and replace the yellow highlighted text before submitting your document. Similarly, please adjust the example tables as necessary (e.g., by adding or removing rows or columns). Appropriate maps, figures, references, etc. should also be included to support the text. Throughout this report, please compare monitoring results to computational model inputs and outputs wherever applicable.

Pursuant to 40 CFR 146.91(a), each semi-annual report must contain:

(1) Any changes to the physical, chemical, and other relevant characteristics of the $CO_2$ stream from the proposed operating data;
(2) Monthly average, maximum, and minimum values for injection pressure, flow rate and volume, and annular pressure;
(3) A description of any event that exceeds operating parameters for annulus pressure or injection pressure specified in the permit;
(4) A description of any event which triggers a shut-off device required pursuant to 40 CFR 146.88(e) and the response taken;
(5) The monthly volume and/or mass of the $CO_2$ stream injected over the reporting period and the volume injected cumulatively over the life of the project;
(6) Monthly annulus fluid volume added; and
(7) The results of monitoring prescribed under 40 CFR 146.90.

The semi-annual report must cover all activities included in the approved Testing and Monitoring Plan. Remember that, pursuant to 40 CFR 146.90, the requirement to maintain and implement an approved Testing and Monitoring Plan is directly enforceable regardless of whether the requirement is a condition of the permit. For more information, see the Class VI guidance documents at https://www.epa.gov/uic/class-vi-guidance-documents.

To avoid duplicative reporting, you are encouraged to provide relevant cross-references to other submissions made with the GSDT.

**Facility Information**

| | |
|---|---|
| Facility name: | Archer Daniels Midland Company |
| Well Name: | CCS#2 |
| Facility contact: | Jason Stahr<br>jason.stahr@adm.com |
| Well location: | Decatur, Macon County, IL |
| Well Coordinates: | 39º 53' 09.32835" N, 88º 53' 16.68306" W |
| Permit number: | IL-115-6A-0001 |
| Report date: | January 30, 2022 |
| Report period: | July 1, 2021 @ 00:00 hrs - January 1, 2022 @ 00:00 hrs |
| Report number: | 29 |

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons that manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

## 1. Overview

***Summary of Operating Parameters***
This report covers the CCS#2 injection monitoring period beginning 07/01/2021 @ 00:00 hours and ending at 01/01/2022 @ 00:00 hours. During the 12-month reporting period, 221,853 metric tons (Mt) of $CO_2$ was injected at an average rate of 1,206 Mt/day resulting in a total mass of 2,522,555 Mt being injected into CCS#2 (See Figure 1). The reservoir pressure changed as a function of injection rate and the total mass of $CO_2$ injected. The average downhole tubing injection pressure (reservoir pressure) was 3,927 psia versus the pre-injection pressure of 2,841 psia equating to an increase in reservoir pressure of 1,086 psi. The actual injection pressure tracked with the forecast injection pressure but due to fouling of the perforated interval there is a 7.9% bias versus the reservoir model. The above confining zone (ACZ) monitoring data at VW#1 and VW#2 show no movement of fluids or $CO_2$ above the confining zone. This is also supported by the injection zone pressure and temperature data which indicate the $CO_2$ is moving along the injection horizon corresponding with the CCS#2 operational parameters. No anomalous operating or reservoir parameters were observed. No changes were observed in GM#2's downhole pressure and temperature monitoring of the St. Peter Sandstone and the shallow and deep groundwater monitoring data show no changes in groundwater chemistry that would indicate movement of fluids or $CO_2$ out of the injection zone.

The injectate stream analysis shows no change in the $CO_2$ quality when compared to the baseline data. The unit's corrosion monitoring system showed a slight increase in corrosion rates on the 13CR-L80 coupon during Q1. The coupon had visible signs of mechanical damage which possibly occurred during installation (i.e. coupon being crushed between the isolation valve's gate and seat). Otherwise, the coupon lacked any unusual corrosion patterns such as pitting, that would indicate active corrosion. This conclusion is supported by the lack of unusual or accelerated corrosion patterns observed on the less resistant A106B or the L-08 coupons. Continuous DTS monitoring of CCS#2 is ongoing and the well's smooth temperature profile indicates good well integrity and no movement of fluid or $CO_2$ behind the casing. Therefore, continuing injection operation does not present an endangerment to the St. Peter Sandstone, the lower most USDW.

***Summary of Operational Deviations***
A summary of the periods in which the operational parameters exceeded the maximum or minimum limits is provided in Table 1. Detailed descriptions of each event are provided in Section 3.

***Maintenance, Inspection, & Annual Sampling***
The annual deep groundwater sampling and the remaining MIT activities were completed during Q4-2021. Prior to sampling GM#2, the St. Peter reservoir T/P monitoring gauge was pulled from the well and underwent annual maintenance and testing. The gauge has not been redeployed due to failure of the cable to meet the specified ductility test. Deploying the gauges utilizing this cable would add significant risk regarding cable failure and losing the gauges downhole. We replaced the cable in Q4-2021 and plan to redeploy the gauges in Q1-2022. In order to monitor the pressure in the St Peter Sandstone (USDW), the well is being water gauged weekly and the results are shown in Figure 8. The pulse neutron logging of CCS#1, CCS#2, VW#1, and VW#2 was moved from 2021 and was conducted in January 17-21, 2022. The letter notifying the agency about the change is included as supplemental information. The schedule for 2022 annual MIT and groundwater sampling activities is shown in Table 2.

As previously reported, we continue to experience an electrical short affecting the performance of the downhole gauges at VW#2, specifically the above confining zone (Zone 5 – Ironton Galesville) and the injection zone, (Zone 3 – Mt. Simon B) monitoring gauges. During the beginning of this reporting period, the Zone 5 gauge completely failed and no data is being received from the instrument. Zone 3 continues to operate but still has an intermittent fault that is affecting data transmission to the surface junction box. We are closely watching the instrument's fault frequency to gauge the rate of deterioration and we are reviewing the deployment of retrievable acoustic and electric line down hole gauges. We continue to use VW#1 to continuously monitor the Ironton Galesville and the Mt Simon B. This should provide enough downhole surveillance to detect any anomaly's that would indicate the movement of fluids or $CO_2$ out of the injection zone. In Q3-2021, we installed an alternative method to monitor VW#2 Zone 5. For description of this monitoring method, please see document named *"20210818 MOC VW#2 Tubing Pressure Mod"* in the supplemental information. This method was effective for 6-8 weeks but minor $CO_2$ leakage into the tubing from the Zone 2 sliding sleeve forced suspension of this monitoring system. To mitigate the $CO_2$ leakage, we plan to inject fluid into Zone 2 in order to displace the free phase $CO_2$ away from the wellbore. This has been proven effective in stopping $CO_2$ leakage through the sleeve. To be clear, this leakage is confined to the production tubing and does not impact the well's external mechanical integrity.

**Table 1.** Summary of deviations from operational control limits.

| Monitoring Condition | No. Events | Total hours | Description of Event(s)[1] |
|---|---|---|---|
| Wellhead Pressure | 0 | 0 | NA |
| DH Tubing Pressure | 2 | 4 | 1) Operational – 4,130 psia (0.10% over limit)<br>2) Operational – 4,127 psia (0.04% over limit) |
| DH Tubing/Annulus ΔP | 1 | 5 | Failed freeze protection & process line froze causing annulus pressure to fall tripping the DHT/A ΔP low limit. |
| Annulus Pressure | 1 | 36 | Failed freeze protection & process line froze causing annulus pressure to fall tripping the DHT/A ΔP low limit. |
| Trip Auto S/D System | 1 | | DH Tubing/Annulus ΔP low limit (12/06/21) |

*Note 1: Detailed description provided in Section 3.*

**Table 2.** Schedule for 2022 annual reservoir fluid sampling and MIT activities.

| Dates | Well | Activity |
|---|---|---|
| January 17-21 | CCS#1&2 | Pulse Neutron Logging[1] |
| January 17-21 | VW#1&2 | Pulse Neutron Logging[1] |
| January 17-21 | CCS#2 | T/P Calibration of DH Gauges |
| March 14-31 | VW#1 | Sample Zone - 3 (Ironton Galesville) |
| March 14-31 | VW#1 | Sample Zones - 2 (Mt Simon B) |
| March 14-31 | VW#2 | Sample Zone - 5 (Ironton Galesville) |
| March 14-31 | VW#2 | Sample Zone - 4 (Mt Simon E) |
| March 14-31 | VW#2 | Sample Zone - 3 (Mt Simon B) |
| Suspended | VW#2 | Sample Zone - 2 (Mt Simon A Upper) |
| March 14-31 | GM#2 | Sample St Peter (Lowermost USDW) |
| January 17-21 | CCS#2 | T/P Calibration of DH Gauges |
| April 1-7 | CCS#2 | Testing of the Automatic S/D System |

*Note 1: Pulse Neutron logging moved from 2021 to 2022.*

## 2. <u>Analysis of $CO_2$ Injectate Stream</u>

***Discussion of Results***

Table 3 presents the $CO_2$ injectate analytical results for the last three quarters (Q1-Q4 2021). The samples were analyzed by Airborne Labs International using standardized procedures for gas chromatography, mass spectrometry, detector tubes, and photoionization. The sample chain-of-custody procedures described in the Quality Assurance and Surveillance Plan (QASP) were employed with no reported deviations. The analytical results indicate no trend or change in the quality of the $CO_2$ injectate and is consistent with the historic sample data generated during the ICCS and IBDP projects.

**Table 3.** Analytical results for $CO_2$ injectate stream.

| Parameter | Q1 2021 2/16/21 | Q2 2021 4/28/21 | Q3 2021 8/4/21 | Q4 2021 11/18/21 | Unit (LOQ) | Analytical method |
|---|---|---|---|---|---|---|
| Carbon Dioxide | Positive 99.5 | Positive 99.5 | Positive 99.8 | Positive 99.9 | % v/v (5.0) | ISBT 2.0 Caustic absorption Zahm-Nagel<br>ALI method SAM 4.1 subtraction method (GC/DID) |
| Nitrogen | 3000 | 820 | 930 | 230 | ppm v/v (10) | ISBT 4.0 (GC/DID) |
| Oxygen | 1000 | 260 | 250 | 15 | ppm v/v (1.0) | ISBT 4.0 (GC/DID) |
| Carbon Monoxide | nd | nd | nd | nd | ppm v/v (2.0) | ISBT 4.0 (GC/DID) |
| Oxides of Nitrogen | nd | nd | nd | nd | ppm v/v (0.5) | ISBT 7.0 Colorimetric |
| Total Hydrocarbons | 120 | 96 | 170 | 170 | ppm v/v (0.1) | ISBT 10.0 THA (FID) |
| Methane | 0.2 | 0.5 | 0.4 | 0.3 | ppm v/v (0.1) | ISBT 10.1 (GC/FID) |
| Acetaldehyde | 5.9 | 5.3 | 11 | 17 | ppm v/v (0.05) | ISBT 11.0 (GC/FID) |
| Sulfur Dioxide | nd | nd | nd | nd | ppm v/v (0.05) | ISBT 14.0 (GC/SCD) |
| Hydrogen Sulfide | 73 | 34 | 49 | 31 | ppm v/v (0.01) | ISBT 14.0 (GC/SCD) |
| Ethanol | 1.3 | 2.9 | 10 | nd | ppm v/v (0.1) | ISBT 11.0 (GC/FID) |

*LOQ = Limit of Quantitation is the lowest amount of analyte quantitatively determined with suitable precision and accuracy.*
*nd = indicates the impurity was not detected and was below method detection limit.*

***Supplemental Material***
The analytical reports for the samples have been uploaded to the GSDT as follows:
Q1 2021 $CO_2$ Analytical Report: ***20210216_Q1_2021_CO2_Analysis.pdf***
Q2 2021 $CO_2$ Analytical Report: ***20210428_Q2_2021_CO2_Analysis.pdf***
Q3 2021 $CO_2$ Analytical Report: ***20210804_Q3_2021_CO2_Analysis.pdf***
Q4 2021 $CO_2$ Analytical Report: ***20211118_Q4_2021_CO2_Analysis.pdf***

## 3. Continuous Recording of Injection Pressure, Rate, and Volume and Annular Pressure

***Discussion of Results***
Figure 1 shows the injection rate monitoring data for the reporting period. During this period, a total of 221,853 metric tons (Mt) of $CO_2$ was injected at an average rate of 1,206 Mt/day. The maximum flowrate achieved was 1,732 Mt/day during which the wellhead pressure reached 1,707 psig. The fluctuations seen in the injection flowrate are due to plant slowdowns as well as downhole fouling of the well's perforated interval. Figure 2 trends the CCS#2 wellhead temperature and pressure data. During this period, the wellhead temperature and pressure averaged 90 °F and 1,734 psig respectively.

In an effort to maximize the injection rate, the downhole pressure was maintained near the maximum downhole limit of 4,125 psia (90% of the calculated reservoir fracture pressure). Operating near this constraint, resulted in two 2-hour periods in which the downhole tubing pressure exceeded this limit.

On August 4, 2021 at 18:00 hrs the pressure averaged 4,130 psia (90.10%) and November 28, 2021 at 1:00 hrs the pressure averaged 4,127 psia (90.04%). Both exceedances are significantly below the reservoir's fracture pressure and no formation or well damage is indicated.

Figure 3 trends the pressure maintained on the CCS#2 injection well annulus. During this period, the annulus pressure averaged 851 psig and no annular fluid was added to the system. Figure 4 shows the CCS#2 injection zone temperature and pressure monitoring data for the gauges set at 6,270 ft. The baseline (pre-injection) reservoir pressure and temperature was 2,841 psia and 116 °F respectively. As injection progressed through the period, the pressure trended with the injectate flow averaging 3,927 psia corresponding to a ΔP of 1,086 psi versus the baseline. The downhole injection temperature averaged 123 °F or a ΔT of 7 °F. Figure 5 charts the difference between the downhole annulus pressure and the tubing pressure thus providing delta pressure (ΔP) monitoring across the downhole packer. During the reporting period, the packer ΔP averaged 340 psi. The automatic shutdown system was activated during one event in which the downhole annulus pressure dropped below the 100-psi minimum limit.

On December 6, 2021 @ 21:00 hrs, the CCS#2 automatic shut-down system was triggered when severe cold weather caused freezing of the transmitter's impulse line after the freeze protection system failed to operate. Once the line froze, no pressure was transmitted to the gauge and the recorded pressure slowly fell from 1,139 psig to below 100 psig tripping the shutdown system. The failure resulted when rodents damaged the system's wiring causing an electrical fault. The heat tracing was subsequently repaired and additional insulation was installed to prevent future damage.

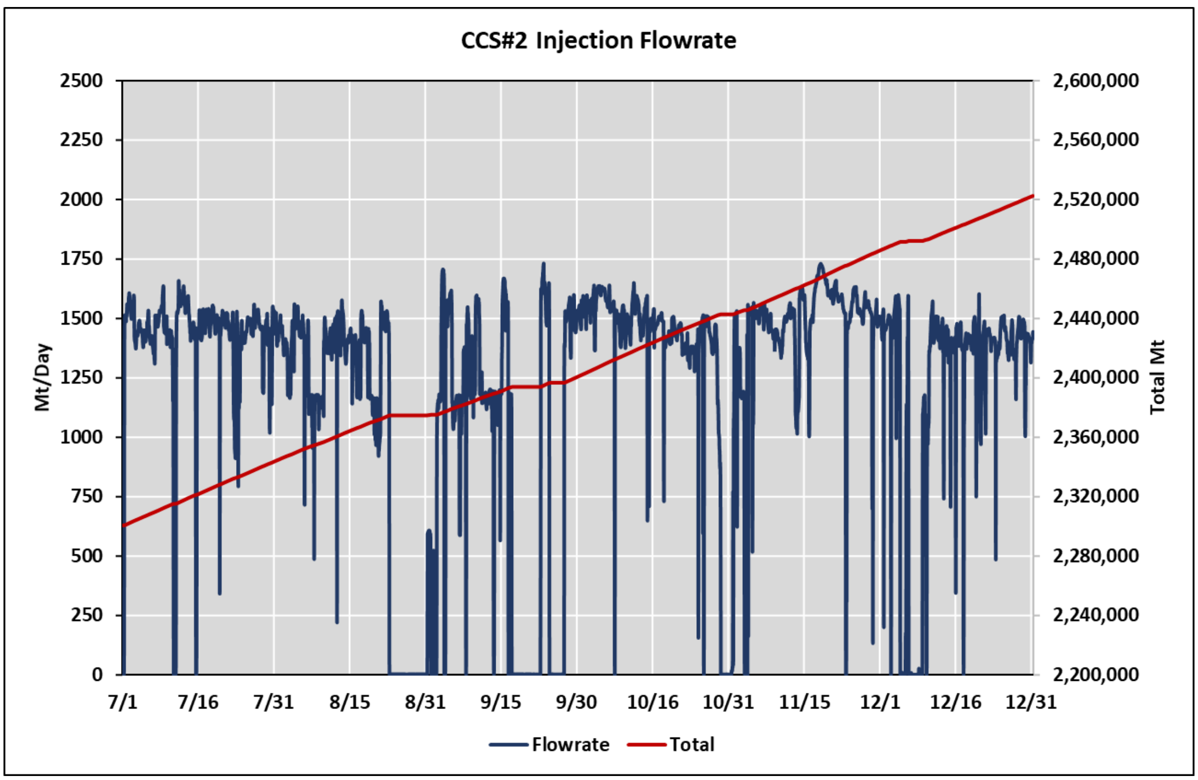


**Figure 1:** CCS#2 - Injection rate monitoring data for Jul-Dec 2021.

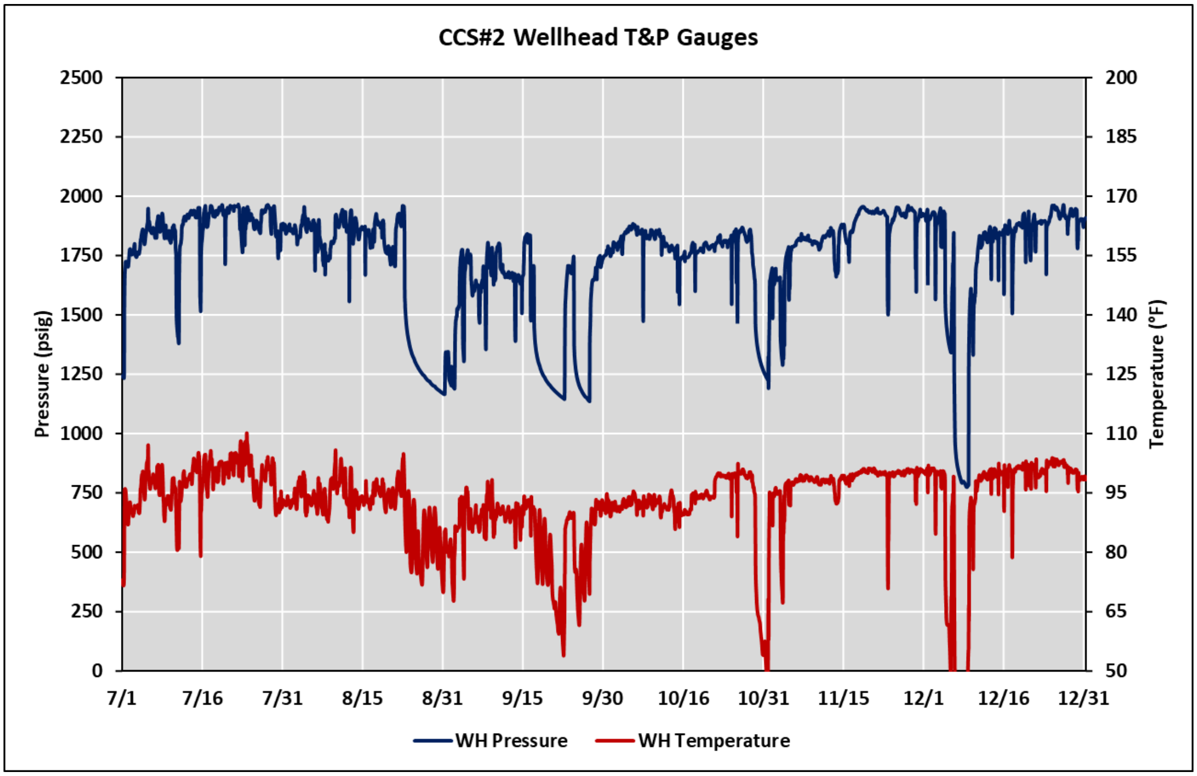


**Figure 2:** CCS#2 wellhead temperature and pressure monitoring data for Jul-Dec 2021.

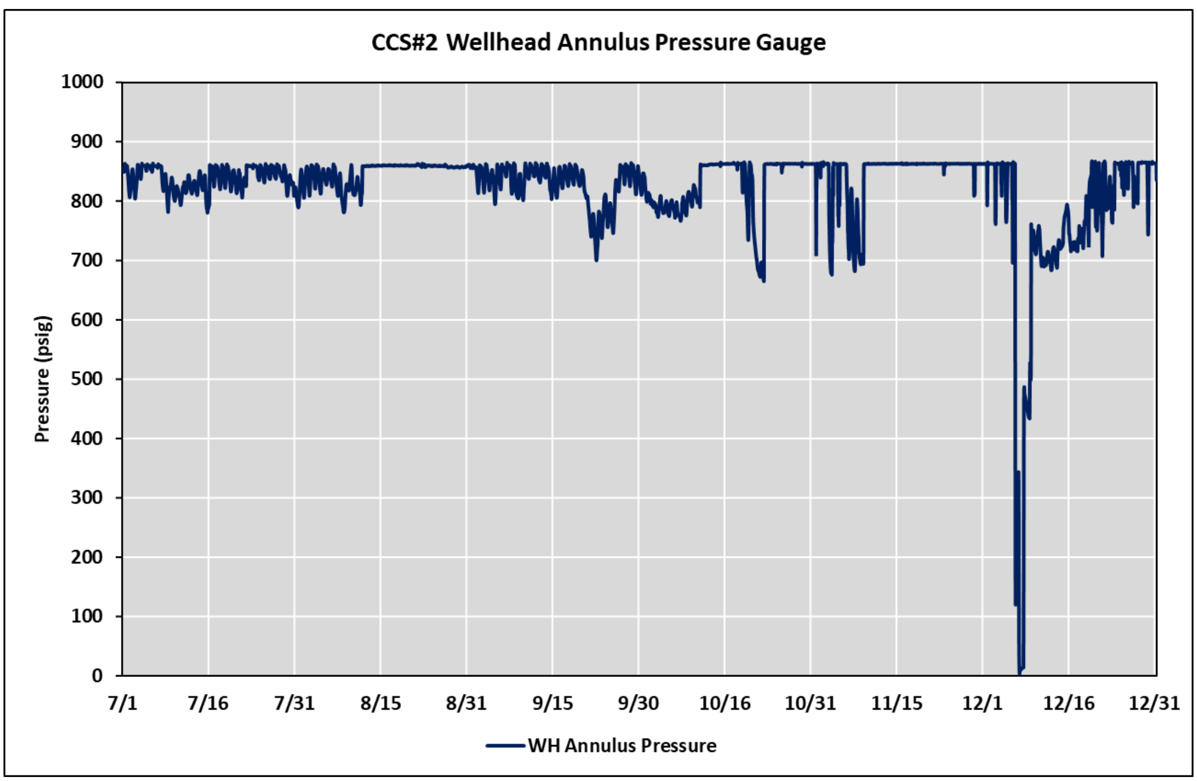


**Figure 3:** CCS#2 wellhead annulus pressure monitoring data for Jul-Dec 2021.

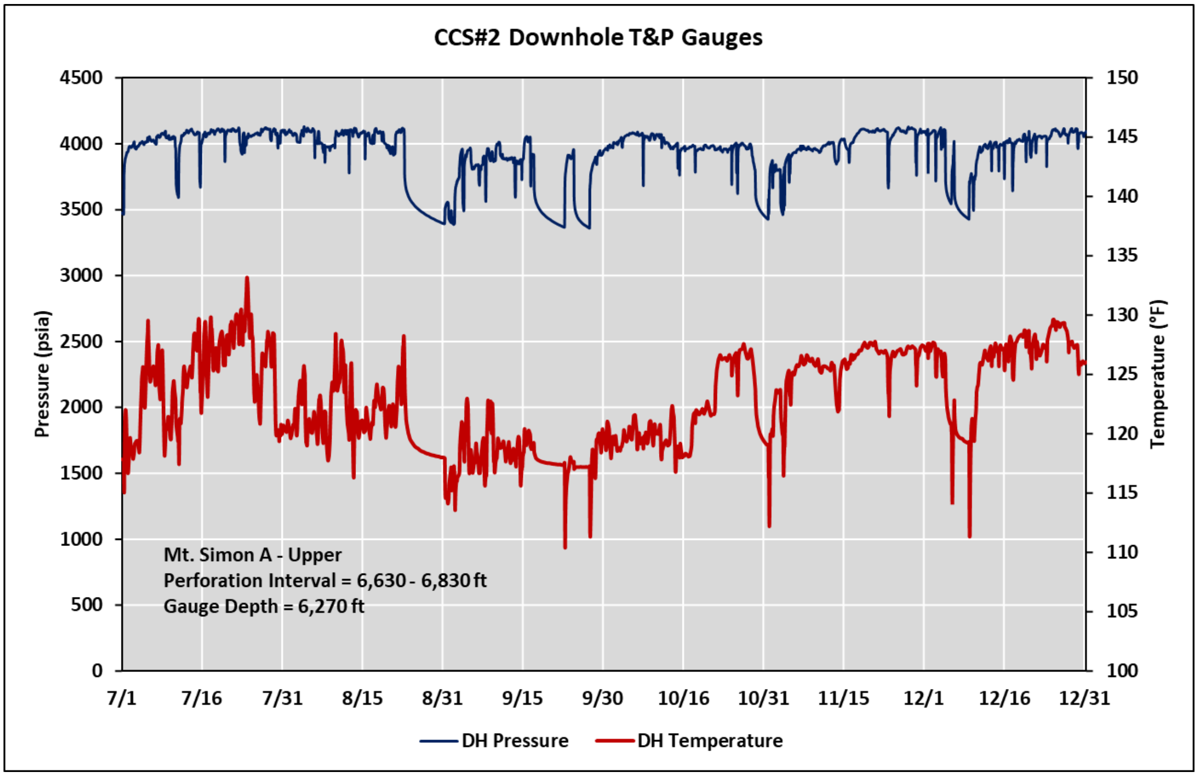


**Figure 4:** CCS#2 downhole temperature and pressure monitoring data for Jul-Dec 2021.

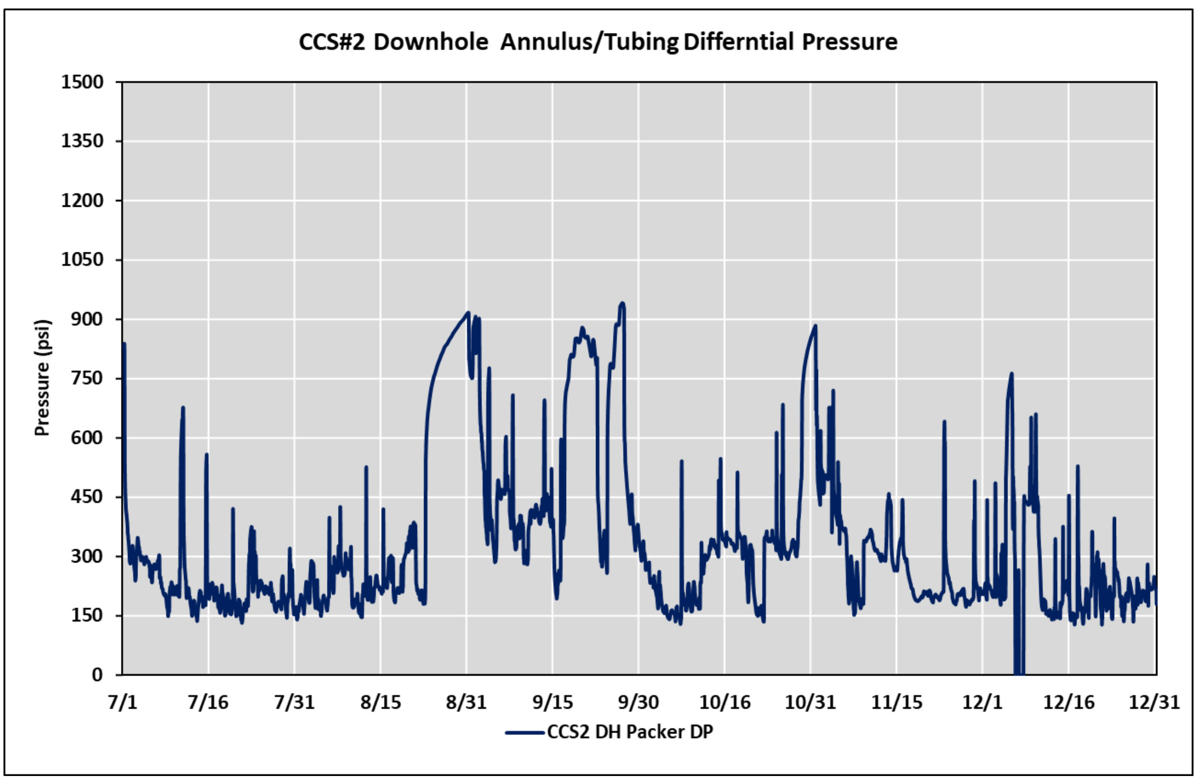


**Figure 5:** CCS#2 downhole annulus and tubing differential pressure monitoring data for Jul-Dec 2021.

Table 4 provides a monthly summary of several important operational limits for CCS#2 and details the parameter's minimum, maximum and average value for each month. Except as mentioned in the incidents above, no other operating limits were exceeded during the monitoring period.

**Table 4.** CCS#2 summary of injection parameters for continuous operational monitoring.

| Parameter (Unit) | Reporting Period | Monthly Summary Values | | |
|---|---|---|---|---|
| | | Average | Minimum | Maximum |
| Injection Pressure (psig) | July 2021 | 1,859 | 1,233 | 1,966 |
| | August 2021 | 1,695 | 1,165 | 1,959 |
| | September 2021 | 1,513 | 1,137 | 1,842 |
| | October 2021 | 1,766 | 1,237 | 1,898 |
| | November 2021 | 1,821 | 1,184 | 1,963 |
| | December 2021 | 1,744 | 770 | 1,965 |
| Injection Rate (Mt/day) | July 2021 | 1,399 | 3 | 1,658 |
| | August 2021 | 996 | 0 | 1,576 |
| | September 2021 | 860 | 0 | 1,731 |
| | October 2021 | 1,356 | 0 | 1,649 |
| | November 2021 | 1,426 | 0 | 1,730 |
| | December 2021 | 1,191 | 2 | 1,602 |
| Injection Volume *Based on DH Reservoir T/P* ($ft^3$/day) | July 2021 | 65,157 | 128 | 80,688 |
| | August 2021 | 44,549 | 0 | 70,139 |
| | September 2021 | 40,577 | 0 | 87,386 |
| | October 2021 | 67,090 | 0 | 82,081 |
| | November 2021 | 63,432 | 0 | 76,914 |
| | December 2021 | 52,691 | 73 | 71,410 |
| Annular Pressure (psig) | July 2021 | 838 | 780 | 871 |
| | August 2021 | 848 | 781 | 873 |
| | September 2021 | 829 | 700 | 868 |
| | October 2021 | 827 | 664 | 871 |
| | November 2021 | 845 | 660 | 869 |
| | December 2021 | 755 | 5 | 892 |

***Supplemental Material***

The operational data file which includes the raw monitoring data, tables, and figures used in this report have been uploaded to the GSDT as follows:

Operational Data File: ***202112_ADM_IL-115-6A-0001_Data.xlsm***

## 4. Carbon Dioxide Volume/Mass Injected and Annular Fluid Added

***Summary of Results***

Table 5 summarizes the monthly injection rate, cumulative mass injected, and the amount of annular fluid added or removed from CCS#2's annulus pressure system. During the reporting period, the monthly amount injected into CCS#2 averaged 36,976 Mt and the total amount injected was 221,853 Mt. At the end of the reporting period, the total mass of $CO_2$ injected into CCS#2 was 2,522,555 Mt. No brine (annular fluid) was added or removed from the annulus system confirming the downhole mechanical integrity of the tubing, casing, and packer.

**Table 5.** Summary of $CO_2$ injected and annular fluid maintenance.

| Reporting Period | $CO_2$ Injected (Mt) | Cumulative $CO_2$ Injected (Mt) | Annulus Fluid Volume +/- Added or Removed (Gallons) |
|---|---|---|---|
| July 2021 | 43,421 | 2,344,122 | 0 |
| August 2021 | 30,841 | 2,374,963 | 0 |
| September 2021 | 25,782 | 2,400,746 | 0 |
| October 2021 | 42,020 | 2,442,766 | 0 |
| November 2021 | 42,887 | 2,485,652 | 0 |
| December 2021 | 36,902 | 2,522,555 | 0 |

***Supplemental Material***
No supplemental information to be provided.

## 5. <u>Corrosion Monitoring</u>

***Summary of Results***
Table 6 shows the results of the corrosion monitoring program. Review of the data shows a slight increase in corrosion rates on the 13CR-L80 coupon during Q1. The coupon had visible signs of mechanical damage which possibly occurred during installation (i.e. coupon being crushed between the isolation valve's gate and seat). Otherwise, the coupon lacked any unusual corrosion patterns such as pitting, that would indicate active corrosion. This conclusion is supported by the lack of unusual or accelerated corrosion patterns observed on the less resistant A106B or the L-08 coupons. Overall, the corrosion monitoring data indicates minimal injectate induced corrosion in the transportation pipeline and injection well. This data is consistent with the historic corrosion data generated during the IBDP's (CCS#1) three-year operational period. The coupons were prepared by EnhanceCo and assessed for corrosion using the American Society for Testing and Materials (ASTM) G1-03, Standard Practice for Preparing, Cleaning, and Evaluating Corrosion Test Specimens (ASTM 2011). The coupons were photographed, visually inspected at 20x power, dimensionally measured to within 0.0001 inches, and weighed to within 0.0001 grams. During the reporting period, there was no deviation from the testing and monitoring plan that would indicate quality assurance/quality control (QA/QC) problems.

One note, there are some visible deposits of material on the surface of the corrosion coupons. This could be corrosion material being generated in the compression equipment, likely the 4$^{th}$ stage compression cylinder. Because this is the trans-critical stage, we are currently developing a project to change the cylinder lubrication to a formulation that is less miscible in super critical $CO_2$.

***Supplemental Materials***
The coupon photos, measurements, and corrosion calculations have been uploaded to the GSDT as follows:
Q1-Q4 2021 Coupons: ***2021_ADM_Corrosion_Coupon_Photos_Q1_Q4.pdf***
Corrosion Calculations: ***202112_CCS#2_Corrosion_Monitoring_Results.xlsx***

**Table 6.** CCS#2 corrosion monitoring results[1].

| Coupon Material Equipment Service | Coupon Number | Monitoring Period | Corrosion Rate (mpy) | Corrosion Categorization | Corrosion Type |
|---|---|---|---|---|---|
| **A106-B** Transport pipeline | 6 | Q1 2021 | 0.127 | Low | Generalized |
| | 5 | Q2 2021 | 0.041 | Low | Generalized |
| | 6 | Q3 2021 | 0.026 | Low | Generalized |
| | 5 | Q4 2021 | 0.023 | Low | Generalized |
| | | | | | |
| **L-80** Long string casing <4,800 ft | 6 | Q1 2021 | 0.181 | Low | Generalized |
| | 5 | Q2 2021 | 0.057 | Low | Generalized |
| | 6 | Q3 2021 | 0.019 | Low | Generalized |
| | 5 | Q4 2021 | 0.019 | Low | Generalized |
| | | | | | |
| **13CR-L80** Long string casing >4,800 ft, injection tubing, and packer | 6 | Q1 2021 | 1.093 | Moderate | MD |
| | 5 | Q2 2021 | 0.229 | Low | Generalized |
| | 6 | Q3 2021 | 0.079 | Low | MD |
| | 5 | Q4 2021 | 0.077 | Low | MD |

*Note 1: Corrosion categorization is based on NACE: SP0775-2013 "Qualitative Categorization of Carbon Steel Corrosion Rates for Oil Production Systems".*

## 6. Above Confining Zone (ACZ) Monitoring

***Discussion of Results – Pressure and Temperature Monitoring***

Table 7 compares the pre-injection reservoir parameters versus the observed reservoir parameters for the ACZ monitoring zones in GM#2 (St. Peter Formation), VW#2 (Ironton Galesville Formation), and VW#1 (Ironton Galesville Formation). Examination of the data shows no significant change occurred during the monitoring period (pre-injection vs. current) thus indicating no movement of fluids or $CO_2$ above the confining zone and therefore indicates that the operation does not present an endangerment to the St. Peter Sandstone, the lower most USDW.

**Table 7:** GM#2, VW#2, & VW#1 ACZ pressure and temperature monitoring.[(1)]

| Parameter | Pressure (psia/psi) | | | Temperature (°F) | | |
|---|---|---|---|---|---|---|
| Well | GM#2 | VW#2 | VW#1 | GM#2[(3)] | VW#2[(4)] | VW#1 |
| Depth[(2)] | 3,450 ft | 5,027 ft | 4,989 ft | 3,450 ft | 5,027 ft | 4,989 ft |
| Formation | St Peter Sandstone | Ironton Galesville | Ironton Galesville | St Peter Sandstone | Ironton Galesville | Ironton Galesville |
| Pre-Injection | 1,397 | 2,112 | 2,086 | 95 | 104 | 104 |
| Average | 1,398 | 2,118 | 2,084 | 103 | 107 | 105 |
| Delta P | 1.3 | 6.1 | -1.7 | 8.2 | 3.7 | 0.1 |
| % Change | 0.1% | 0.3% | -0.1% | 8.6% | 3.6% | 0.1% |

*Note 1: Data Collection Time Period = 7/1/20 - 1/1/21. Pressure reported as reservoir=psia & dP=psi.*
*Note 2: Depths reported are gauge depths.*
*Note 3: Based on CCS#2 DTS data.*
*Note 4: Based on VW#2 DTS data.*

Figure 6 and Figure 7 trend the downhole pressure and temperature for the Ironton Galesville, the formation directly above the injection zone seal (Eau Claire Shale) at VW#2 and VW#1 respectively. Figure 8 trends GM#2's downhole pressure and temperature for the St. Peter Sandstone, the lower most USDW. From these figures, one observes no significant change in reservoir temperature or pressure that would indicate the movement of brine or $CO_2$ above the seal formation. Figure 6 shows the time period in which the alternative pressure monitoring method was employed at VW#2. The monitoring was effective until October when $CO_2$ began leaking through the Zone 2 sliding sleeve slowing increasing the wellhead pressure. Because the downhole gauges are out of GM#2, Figure 8 plots the results of the weekly water gauge conducted during this period. The tabular data used to generate the figure is shown in Table 8. The well's water level is consistent with the hydrostatic level needed for the 1,400 psia reservoir pressure.

As discussed in the summary section and denoted in Figure 6, since September 14, 2020, an intermittent short on VW#2's downhole communications line is affecting the ability to continuously monitor the reservoir conditions of Ironton Galesville (ACZ) at VW#2. The data indicates there is an intermittent fault in the communication line between the downhole gauges and the surface junction box. During the instrument's energization and data transmission cycle, the line is subject to shorting. If the fault occurs during the data transmission cycle, the signal is corrupted and the ARCCON data acquisition unit reports null values. Electrical checks taken from the VW#2 junction box to the downhole cable showed a reverse resistance of 7.05 kilo-ohms, which is indicative of a short or leak. Unfortunately, there is no means to institute repairs without pulling the complete downhole assembly, essentially a complete well workover. Therefore, we are closely watching the instrument's fault frequency to gauge the rate of deterioration.

In Q3-2021, we installed an alternative method to monitor VW#2 Zone 5. For description of this monitoring method, please see document named *"20210818 MOC VW#2 Tubing Pressure Mod"* in the supplemental information. This method was effective for 6-8 weeks but minor $CO_2$ leakage into the tubing from the Zone 2 sliding sleeve forced suspension of this monitoring system. To mitigate the $CO_2$ leakage, we plan to inject fluid into Zone 2 in order to displace the free phase $CO_2$ away from the wellbore. This has been proven effective in stopping $CO_2$ leakage through the sleeve. To be clear, this leakage is confined to the production tubing and does not impact the well's external mechanical integrity.

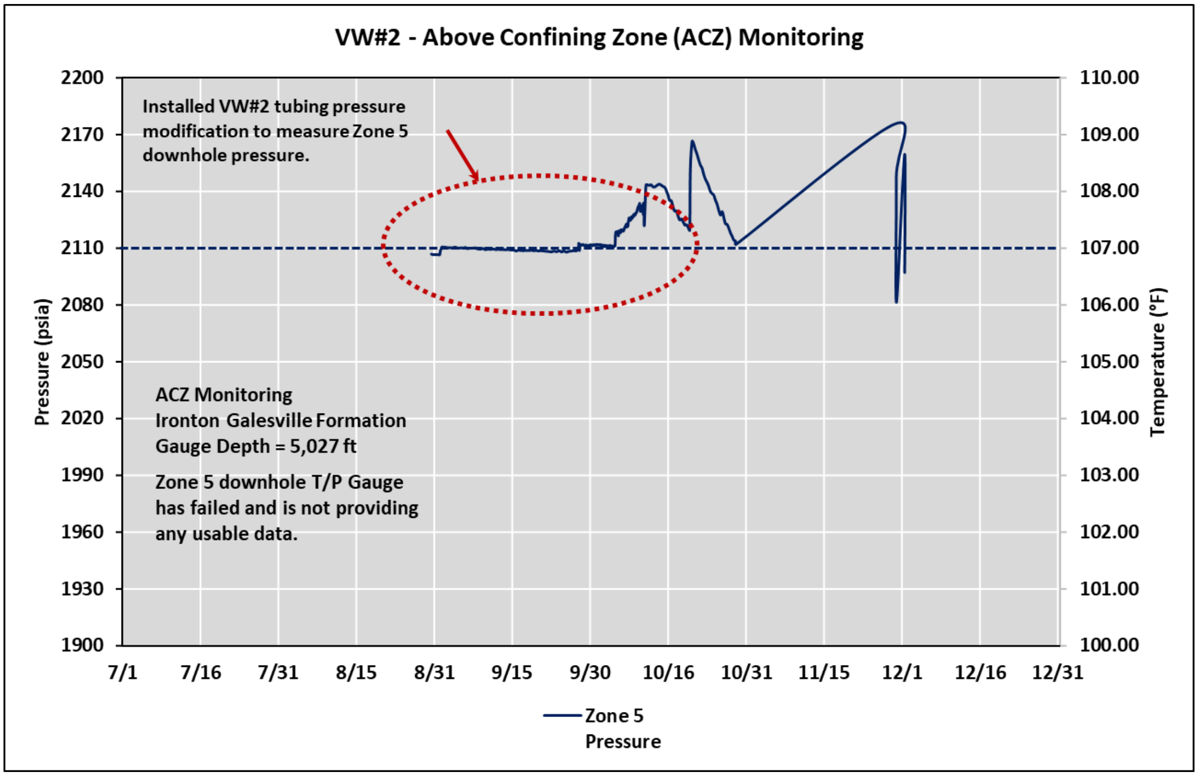


**Figure 6:** VW#2 ACZ monitoring of the Ironton Galesville Formation for Jul-Dec 2021.

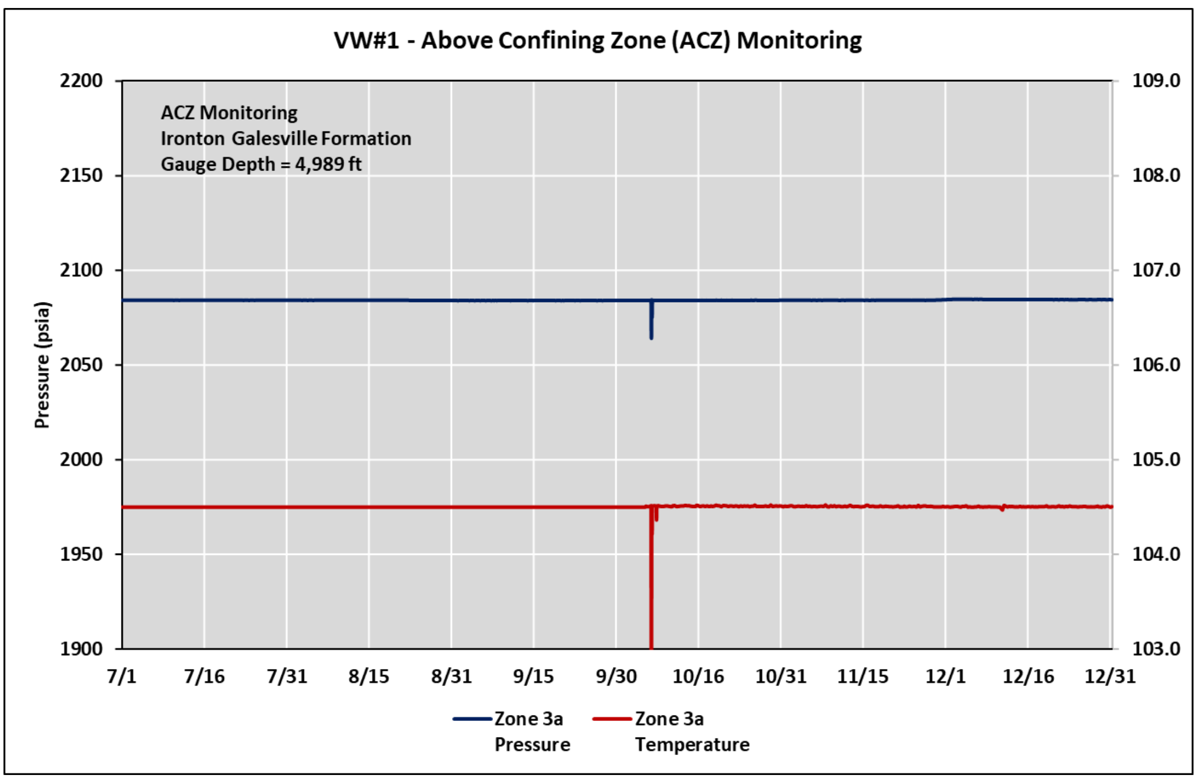


**Figure 7:** VW#1 ACZ monitoring of the Ironton Galesville Formation for Jul-Dec 2021.

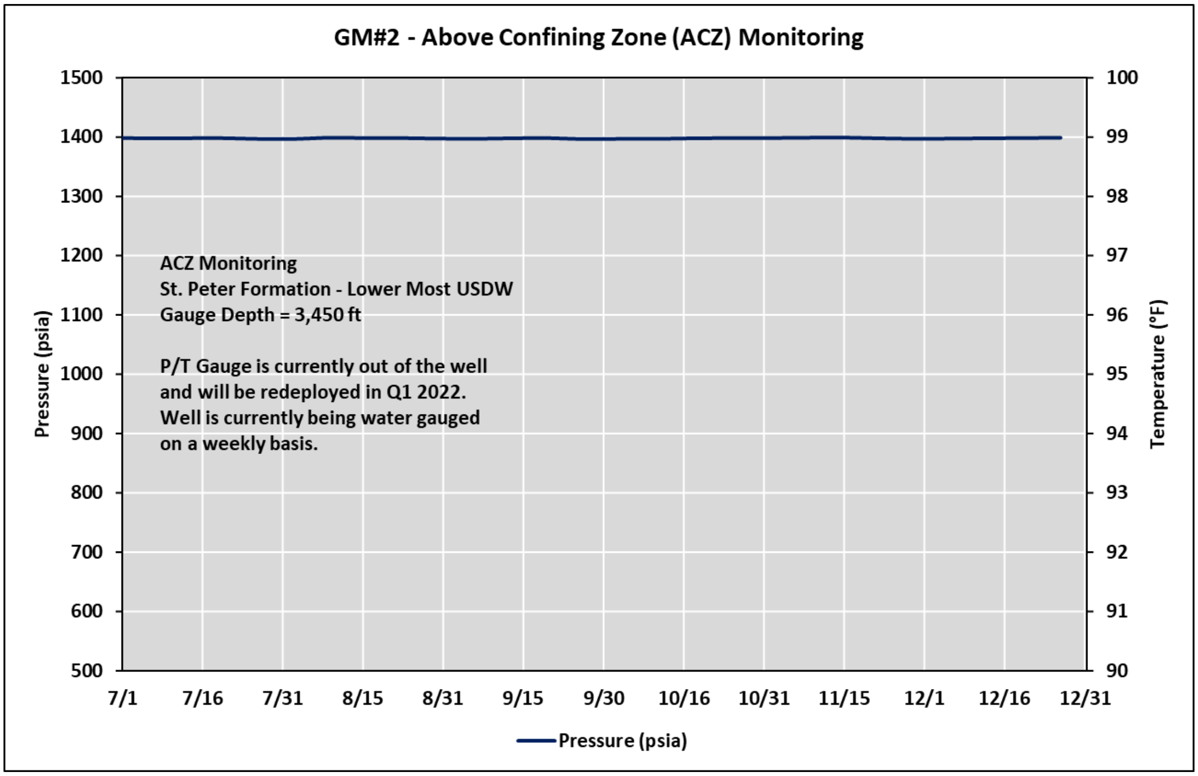


**Figure 8:** GM#2 ACZ monitoring of the St. Peter Formation for Jul-Dec 2021.

**Table 8:** GM#2 Water Gauge Tabular Data.

| Date | Water Gauge Depth (ft) | Pressure (psia) | Date | Water Gauge Depth (ft) | Pressure (psia) |
|---|---|---|---|---|---|
| 1/5/2021 | 197 | 1,398 | 7/26/2021 | 199 | 1,397 |
| 1/18/2021 | 193 | 1,400 | 8/2/2021 | 200 | 1,397 |
| 2/1/2021 | 192 | 1,400 | 8/9/2021 | 195 | 1,399 |
| 2/8/2021 | 198 | 1,397 | 8/16/2021 | 196 | 1,398 |
| 2/18/2021 | 196 | 1,398 | 8/23/2021 | 196 | 1,398 |
| 2/25/2021 | 195 | 1,399 | 8/30/2021 | 198 | 1,397 |
| 3/5/2021 | 197 | 1,398 | 9/6/2021 | 199 | 1,397 |
| 3/15/2021 | 200 | 1,397 | 9/13/2021 | 197 | 1,398 |
| 3/23/2021 | 196 | 1,398 | 9/20/2021 | 196 | 1,398 |
| 3/30/2021 | 199 | 1,397 | 9/27/2021 | 200 | 1,397 |
| 4/6/2021 | 195 | 1,399 | 10/4/2021 | 199 | 1,397 |
| 4/15/2021 | 200 | 1,397 | 10/11/2021 | 199 | 1,397 |
| 4/22/2021 | 194 | 1,399 | 10/18/2021 | 197 | 1,398 |
| 5/3/2021 | 196 | 1,398 | 10/25/2021 | 196 | 1,398 |
| 5/12/2021 | 199 | 1,397 | 11/1/2021 | 196 | 1,398 |
| 5/19/2021 | 192 | 1,400 | 11/8/2021 | 195 | 1,399 |
| 5/31/2021 | 197 | 1,398 | 11/15/2021 | 194 | 1,399 |
| 6/7/2021 | 197 | 1,398 | 11/22/2021 | 197 | 1,398 |
| 6/16/2021 | 196 | 1,398 | 11/29/2021 | 199 | 1,397 |
| 6/23/2021 | 199 | 1,397 | 12/6/2021 | 198 | 1,397 |
| 6/30/2021 | 196 | 1,398 | 12/13/2021 | 197 | 1,398 |
| 7/5/2021 | 197 | 1,398 | 12/20/2021 | 196 | 1,398 |
| 7/12/2021 | 197 | 1,398 | 12/27/2021 | 195 | 1,399 |
| 7/19/2021 | 196 | 1,398 | | | |

***Discussion of Results – Groundwater Monitoring***
The site's groundwater monitoring program for the two UIC Class VI permits (CCS#1 and CCS#2) is being conducted by the Illinois State Geological Survey. Because the two UIC permits have consistent requirements for the groundwater testing and monitoring, we are providing a summary of all the groundwater monitoring in this report. Because of the report's size, it is being submitted as supplemental material.
Since the last report (dated July 27, 2021), additional sampling events have occurred. Between July 22, and October 14, 2021, two quarterly shallow groundwater sampling events (July and October 2021) occurred. The new results are included in this report. No deep fluid sampling has occurred since July 17, 2021.
Time series graphs for shallow groundwater compliance parameters were updated and the corresponding interpretations were reviewed. The newly obtained data are consistent with all historical data cited in the July 27, 2021 report, and the major conclusion remains the same. Specifically, interpretations of all shallow groundwater data to date indicate that no trends or changes in shallow groundwater chemistry have occurred as a result of CO2 injection in Decatur. The variability observed in shallow water quality data are attributed to factors including natural groundwater heterogeneity, seasonal groundwater variability, initial effects of well installation, and equipment performance. No changes in water quality were observed that would indicate brine or injected CO2 were introduced into the shallow groundwater environment. Further, there are natural differences between the chemistry of groundwater from wells screened in the shallow Pennsylvanian bedrock (i.e., the G-series wells used for the IBDP) and wells screened in the glacial materials of the Lower Glasford Formation (i.e., the LG wells used for the IL-ICCS project). In general, the concentration of alkalinity, dissolved carbon dioxide, barium, calcium, iron, magnesium, manganese, and silicon from LG wells are greater than in the bedrock wells, whereas specific conductance and the concentrations of total dissolved solids, bromide, chloride, fluoride, and sodium are lower than the bedrock wells. These concentration variations are interpreted as the result of mineralization by natural water-rock interactions and groundwater movement within the strata being monitored.

***Supplemental Materials***
The groundwater monitoring report has been uploaded to the GSDT as follows:
GW Report Name: ***202112_IL-115-6A-0001-0002_GWM_Report.pdf***
GW COAs: ***202112_IL-115-6A-0001-0002_Shallow_Deep_GWM_COAs.pdf***

## 7. External Mechanical Integrity Testing

***Discussion of Results***
No external MIT was conducted on CCS#1 during the reporting period. Continuous DTS monitoring of CCS#2 is ongoing and the 24-hour period for December 31, 2021 (end of the reporting period) is shown in Figure 9 and Figure 10. The smooth temperature profile indicates good well integrity and no movement of fluids/$CO_2$ behind the casing.

***Supplemental Material***
CCS#2 DTS Tabular Data: ***20211231_CCS#2_DTS_Data.xls***

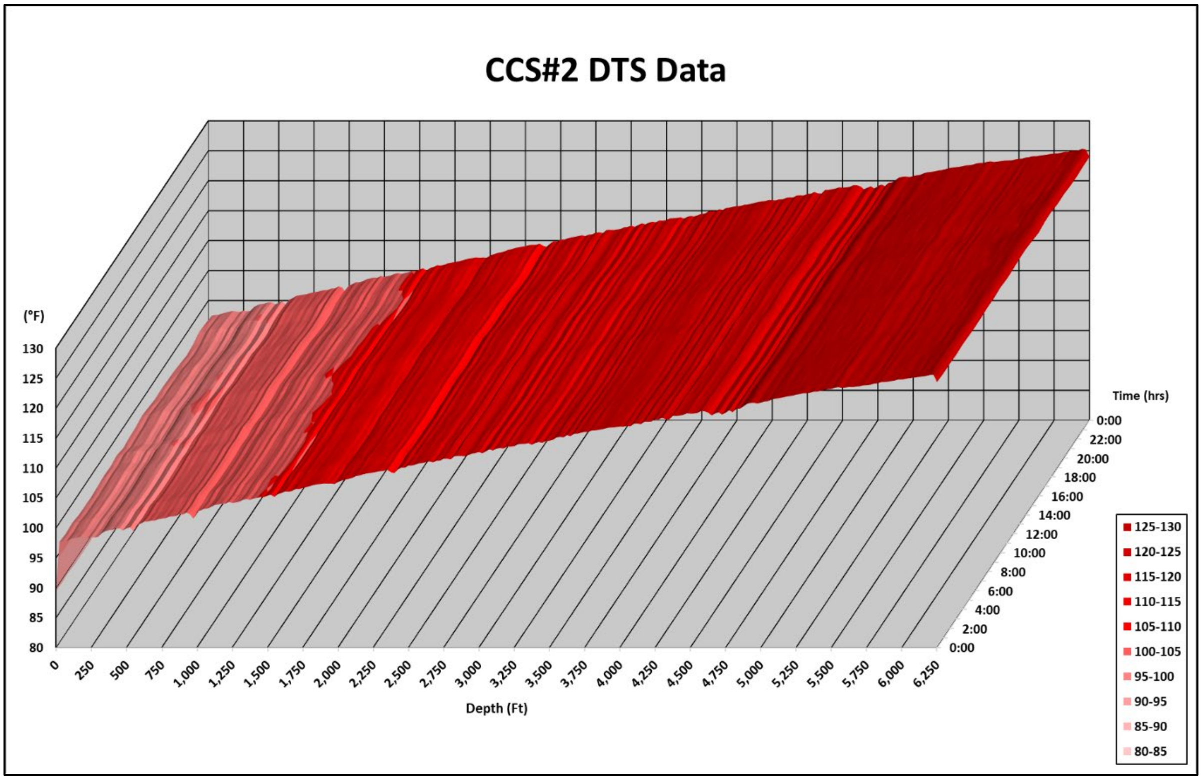


**Figure 9:** CCS#2 DTS data in 3-dimensional view for last day of reporting period 12/31/2021.

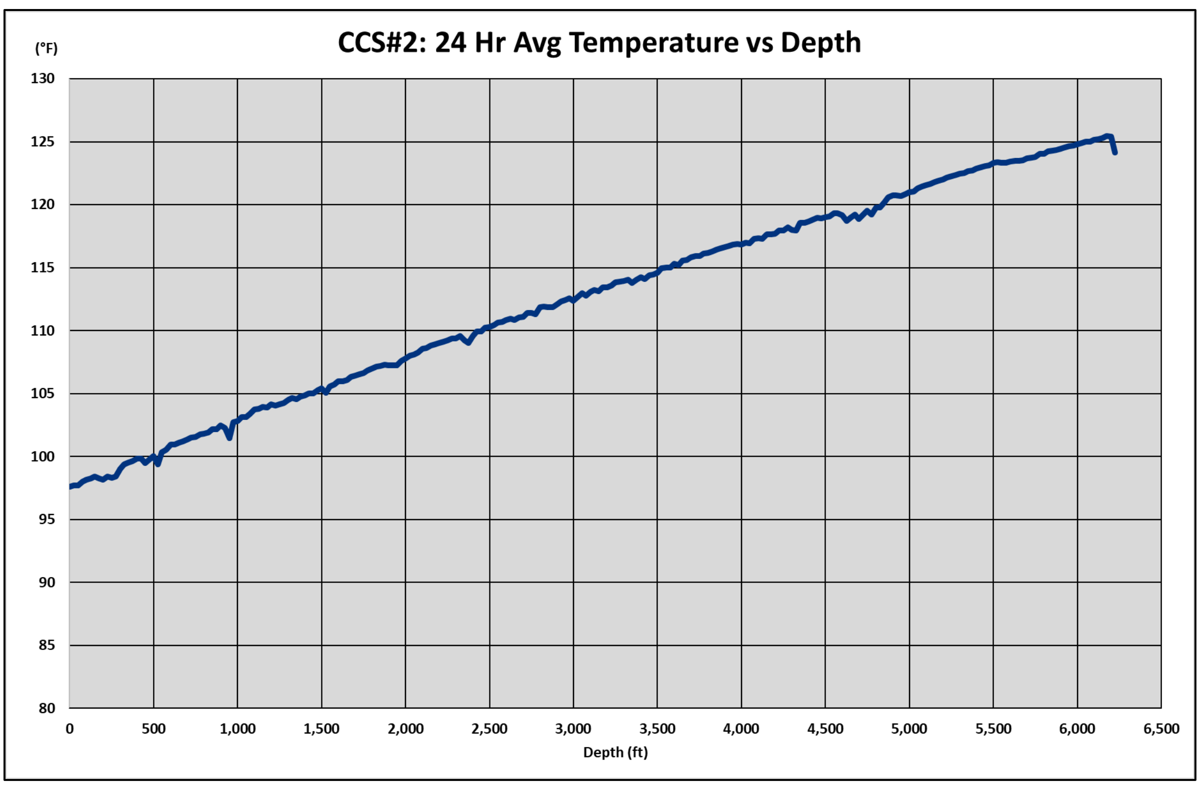


**Figure 10:** CCS#2 24-hour average DTS temperature versus well depth for 12/31/21.

## 8. Pressure Fall-Off Testing

***Discussion of Results***

No pressure fall-off testing was conducted during the reporting period. The permit specifies a pressure fall-off test for CCS#2 at approximately halfway through the injection period or after 2.75 million Mt of $CO_2$ have been injected. Based on current injection rates, this threshold should be met in November 2022. The project team will plan, schedule, and notify the Agency, in accordance with the UIC Class VI requirements.

***Supplemental Material***

No supplemental information to be provided.

## 9. Carbon Dioxide Pressure-Front and Plume Tracking

***Summary of Results and Comparison to Reservoir Model***

The subsurface monitoring data indicate the $CO_2$ pressure and plume fronts are developing in a manner that is consistent with the results forecasted by the updated (2018) Eclipse reservoir flow model. Table 9 compares the actual reservoir pressure with the pressure forecast by the Eclipse model. The actual and forecast data have a good correlation. The monitoring wells are within ~2% of the predicted pressures. CCS#1 is within 4% of the forecast, but CCS#2 deviates from the forecast by 9.3% or 351 psi higher than projected. The CCS#2 bias is due to downhole fouling of the perforated interval.

Table 10 details the results of the logs and compares the injectate flow distribution observed during each run. From this data, it appears that a significant portion of the injectate flow shifted from the upper to the lowest set of perforations. This shift in the well's flow distribution as well as the casing diameter reduction shown by the tool's caliper readings (not shown), confirms the buildup of foreign material around the upper perforated interval. Figure 11 compares the predicted injection zone pressure predicted versus the actual pressure recorded at CCS#2. One can observe that the two pressures correlate closely during the first million tons of injection but deviates during the subsequent injection finally reaching a ~500 psi differential at 2.0 million tons. The bias between the actual and the forecast pressure is due mainly to the downhole fouling we are experiencing at CCS#2. Eliminating the fouling should correct the observed model bias. If the fouling remains, modification of reservoir model parameters (i.e. skin factor) will be needed to better align the model with the observed pressure.

Figure 12 - Figure 17 trends the actual versus the forecast differential pressure within the injection zone for each monitoring well. From these figures, one can see close correlation between the predicted reservoir pressure response versus the actual response. This strongly support that the static geophysical (Petrel) and the dynamic reservoir flow (Eclipse) models well characterize our storage site and the pressure and plume fronts are behaving as forecast in the model. One exception can be seen with regard to Figure 17. This chart trends the CCS#1 injection zone pressure versus the model pressure. Clearly there is an unknown artifact that is causing a significant bias one does not see in the other monitoring wells. One theory is that unresolved faults proximate to the interface of the Precambrian with the Mt Simon (Argenta) are channeling pressure. These faults would not present a leakage risk but could provide a conduit to transmit pressure more directly from the CCS#2 injection well to CCS#1. The results of the 2021 3D seismic survey may shed additional light on this phenomenon.

**Table 9:** Comparison of actual reservoir pressure versus 2018 Eclipse model forecast[1].

| Well | CCS#1 | CCS#2 | VW#1 | | | VW#2 | | |
|---|---|---|---|---|---|---|---|---|
| Depth[2] | 7,015 ft | 6,725 ft | 6,970 ft | 6,420 ft | 6,409 ft | 7,041 ft | 6,681 ft | 6,524 ft |
| Formation | Argenta | Mt Simon A Lower | Mt Simon A Lower | Mt Simon B | Mt Simon B | Mt Simon A Lower | Mt Simon B | Mt Simon E |
| Zone | Injection | Injection | Zone 1 | Zone 2 | Zone 3 | Zone 1 | Zone 2 | Zone 3 |
| Actual P | 3,066 | 3,935 | 3,215 | 3,174 | 3167 | 3243 | 3,240 | 3,171 |
| Forecast P | 3,184 | 3,635 | 3,235 | 3,113 | 3108 | 3274 | 3,331 | 3,108 |
| Delta P | 117 | 301 | 19 | 61 | 59 | 31 | 91 | 63 |
| % Delta | 3.8% | 7.9% | 0.6% | 1.9% | 1.9% | 0.9% | 2.8% | 2.0% |

*Note 1: Data Collection Time Period = 7/1/20 - 1/1/21. Pressure reported as reservoir=psia dP=psi*
*Note 2: Monitoring well depths are reported as gauge depths while CCS#1 & CCS#2 depths are the middle of the perforated interval.*

**Table 10:** Comparison of 2017, 2018, and 2019 Spinner Logs

| Perforation Interval (ft) | Perforation Interval Thickness (ft) | 04/08/2017 Rate = 1050 Mt/day | 03/29/2018 Rate = 1040 Mt/day | 03/08/2019 Rate = 1121 |
|---|---|---|---|---|
| **6,630-6,670** | 40 | 19% | 0% | 0% |
| **6,680-6,725** | 45 | 8% | 0% | 0% |
| **6,735-6,775** | 40 | 3% | 5% | 6.5% |
| **6,787-6,825** | 38 | 70% | 95% | 93.5% |

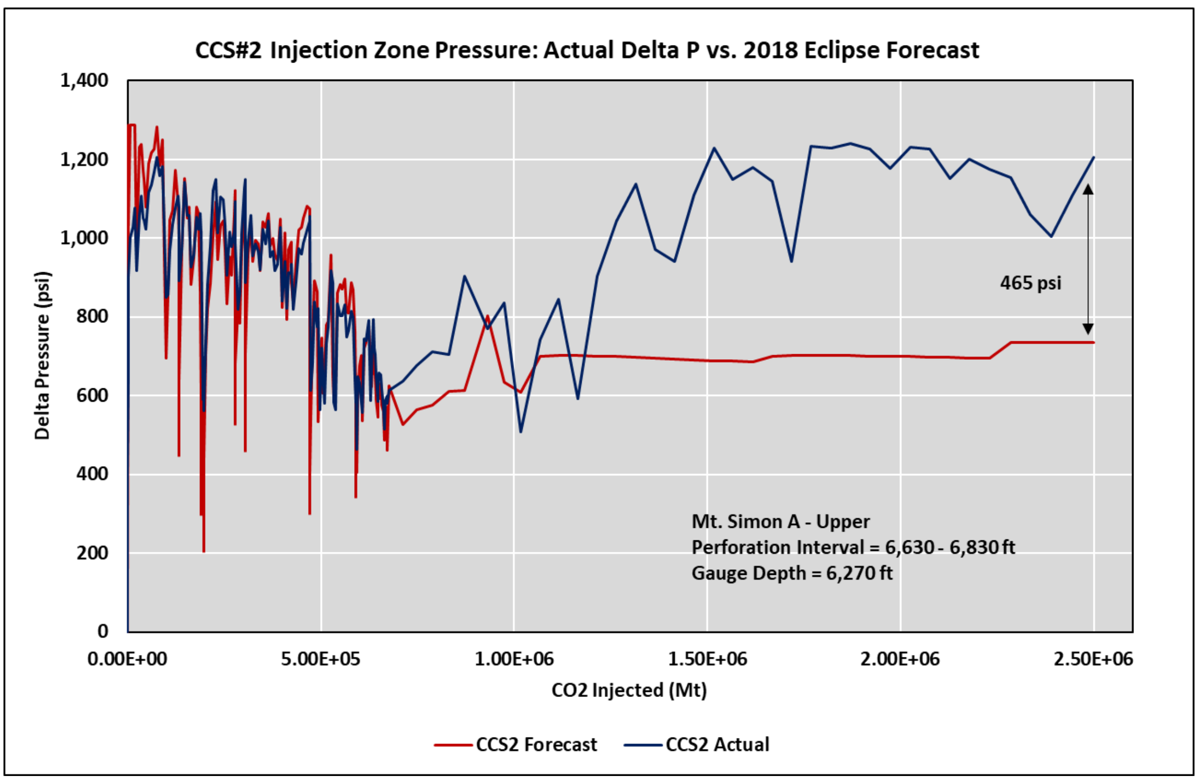


**Figure 11:** CCS#2 comparison of the downhole injection pressure versus the forecast pressure generated by the 2018 Eclipse reservoir model.

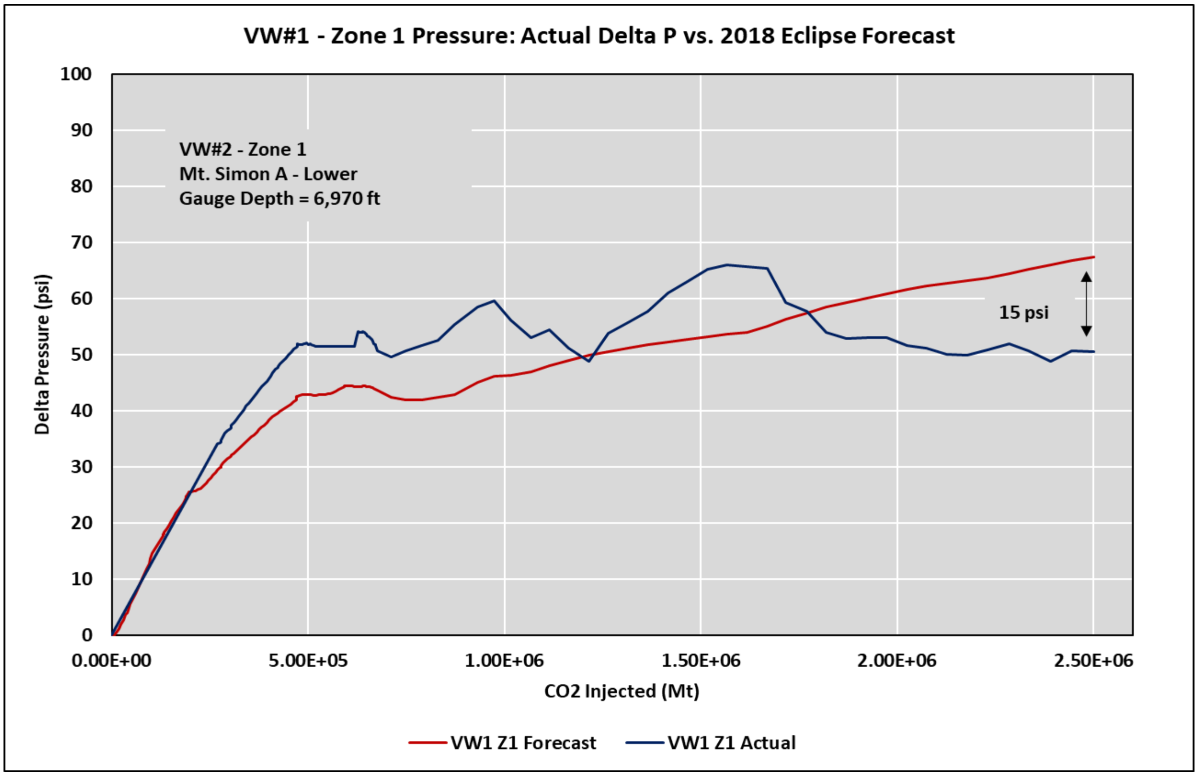


**Figure 12:** VW#2 Zone 1 differential pressure comparison of actual versus 2018 Eclipse forecast.

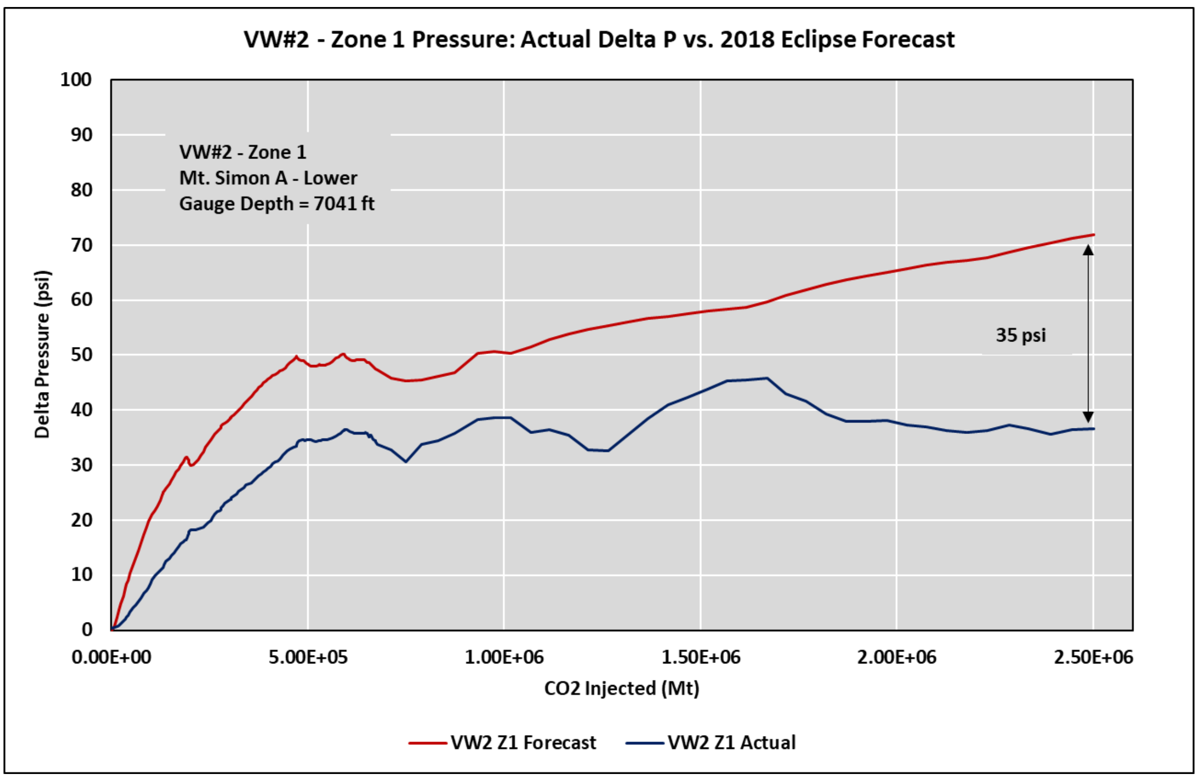


**Figure 13:** VW#1 Zone 1 differential pressure comparison of actual versus 2018 Eclipse forecast.

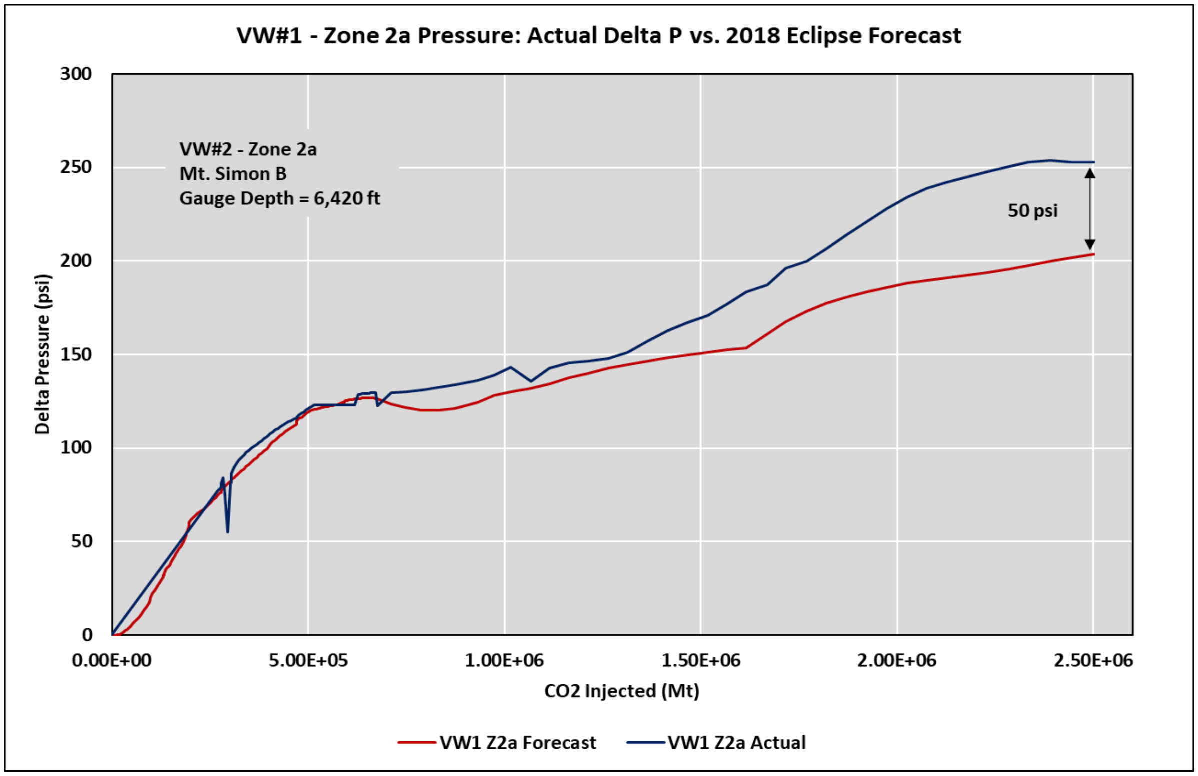


**Figure 14:** VW#1 Zone 2a actual reservoir differential pressure versus 2018 Eclipse forecast.

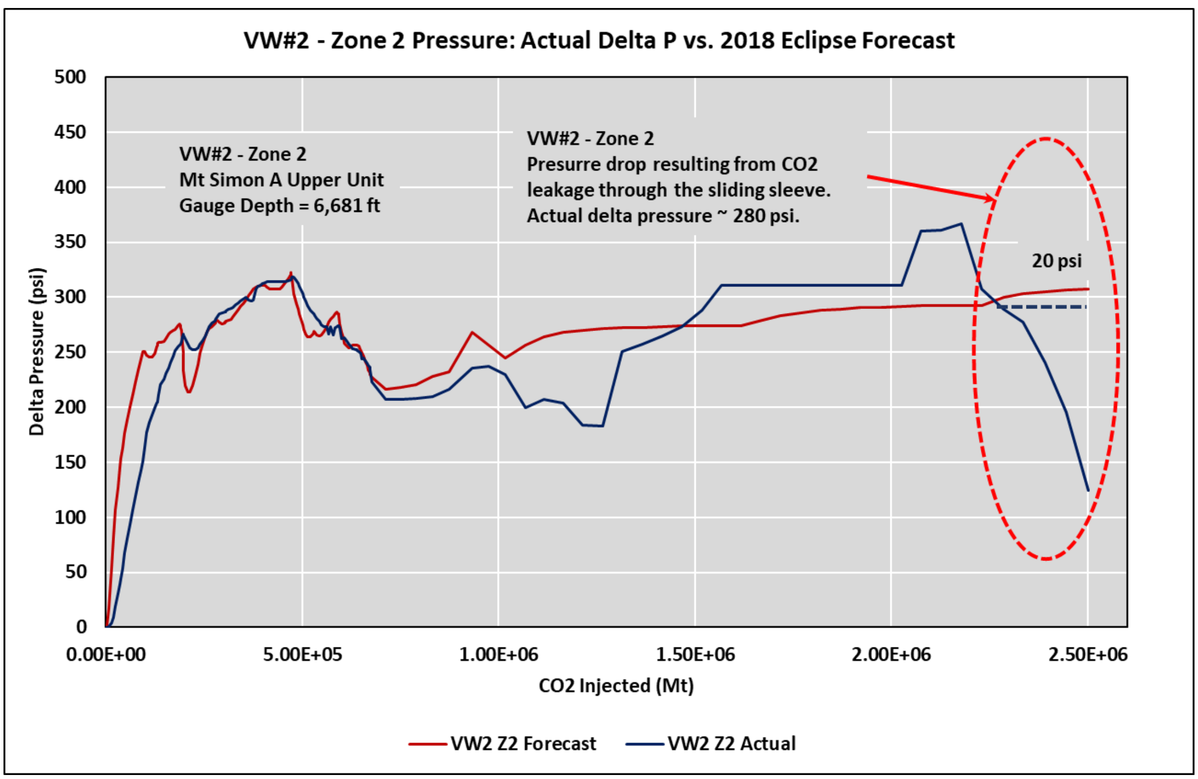


**Figure 15:** VW#2 Zone 2 actual reservoir differential pressure versus 2018 Eclipse forecast.

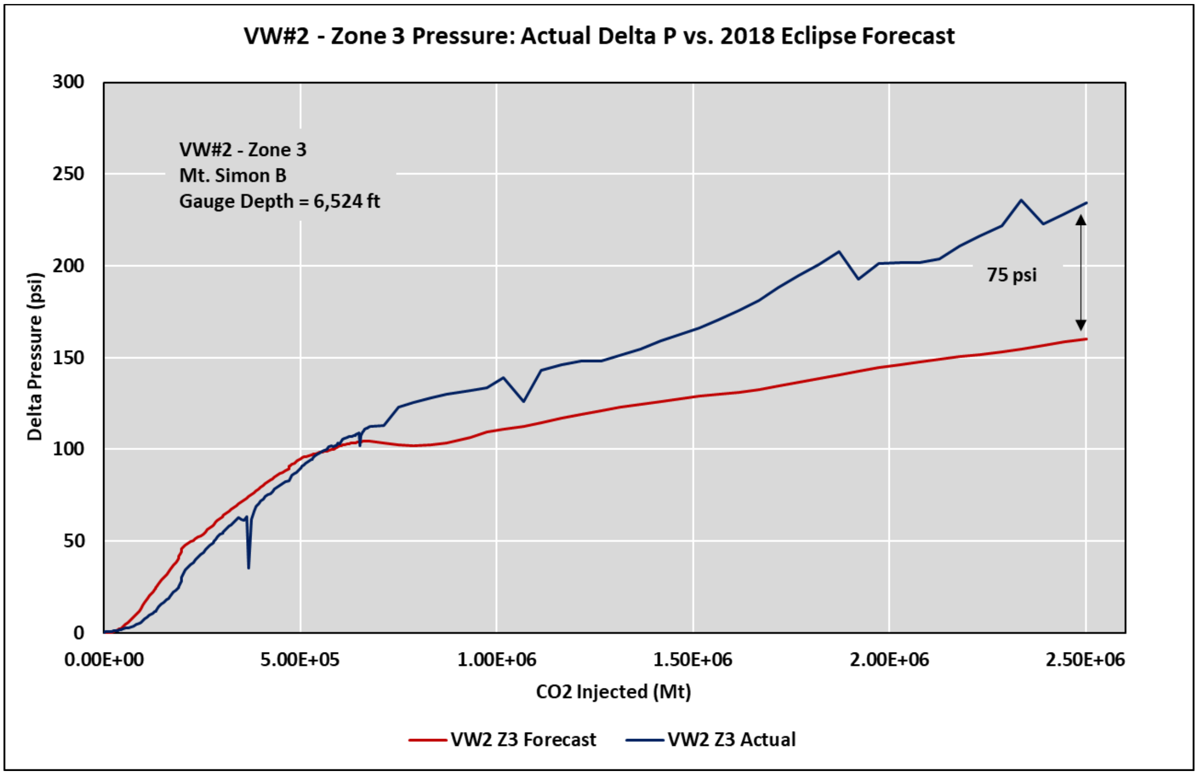


**Figure 16:** VW#2 Zone 3 actual reservoir differential pressure versus 2018 Eclipse forecast.

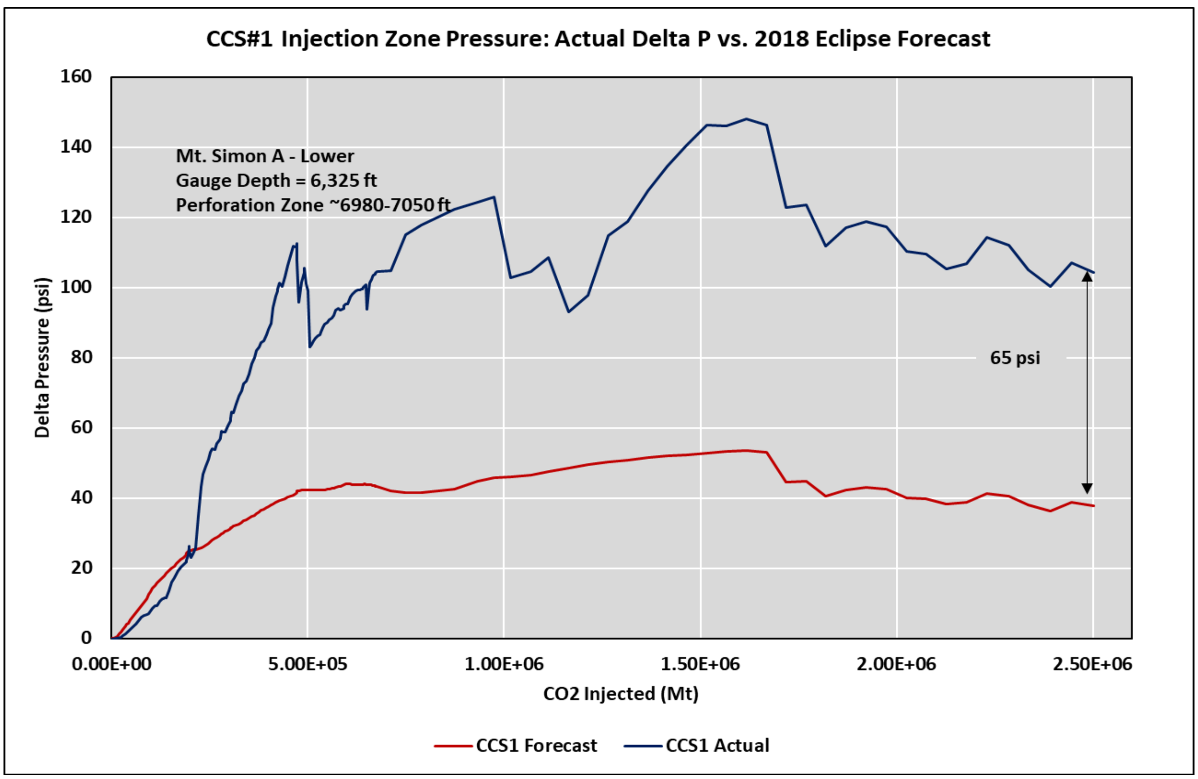


**Figure 17:** CCS#1 injection zone actual reservoir differential pressure versus 2018 Eclipse forecast.

***Discussion of Results – Pressure-Front Tracking***

Table 11 shows the injection zone pressure gradient by comparing VW#1 and VW#2's zone pressures against the pre-injection pressures. Inspection of the data shows that VW#2-Zone 2 pressure had the greatest pressure response: increasing approximately 9.7% ($\Delta P$=293 psi) over the baseline pressure. VW#2-Zone 2 monitors the Mt. Simon A Upper unit at a depth that matches the CCS#2 injection interval. VW#1-Zone 2 and VW#2-Zone 3 monitor the pressure in the Mt. Simon B unit. VW#1-Zone 2 monitors the top of the Mt. Simon B while VW#2-Zone 3 monitors conditions in the middle of the unit. The pressure responses in these zones are consistent with the development of a uniform pressure gradient. VW#2-Zone 4 monitors the Mt. Simon E unit and this zone's pressure response is consistent with the other monitoring zones. The pressure response in the Mt. Simon A Lower unit is monitored in Zone 1 for VW#1 and VW#2 and these readings appear consistent with the other data.

**Table 11:** VW#1 and VW#2 injection zone pressure monitoring.[1]

| | VW#2 (2,600 ft)[3] | | | | VW#1 (2,700 ft)[3] | |
|---|---|---|---|---|---|---|
| Depth[2] | 7,041 ft | 6,681 ft | 6,524 ft | 5,848 ft | 6,970 ft | 6,420 ft |
| Formation | Mt Simon A Lower | Mt Simon A Upper | Mt Simon B | Mt Simon E | Mt Simon A Lower | Mt Simon B |
| Zone | Zone 1 | Zone 2 | Zone 3 | Zone 4 | Zone 1 | Zone 2 |
| Pre-Injection | 3,207 | 3,031 | 2,954 | 2,620 | 3,165 | 2,922 |
| Average | 3,243 | 3,267 | 3,163 | 2,662 | 3,215 | 3,174 |
| Maximum | 3,245 | 3,323 | 3,194 | 2,748 | 3,217 | 3,176 |
| Max Delta P | 38 | 293 | 239 | 127 | 52 | 254 |
| % Change | 1.17% | 9.65% | 8.10% | 4.86% | 1.64% | 8.70% |

*Note 1: Data Collection Time Period = 7/1/20 - 1/1/21. Pressure reported as reservoir=psia & dP=psi.*
*Note 2: Depths reported are gauge depths.*
*Note 3: Approximate distance from injection well (CCS#2).*

Figure 18: and Figure 19 chart the pressure and temperature of the four injection monitoring zones in VW#2 during the reporting period. Observation the Upper Mt. Simon A (VW#2 - Zone 2) shows the pressure began at 3,400 psia and gradually decrease to about 3,250 psia during the monitoring period. The falling pressure is due to lower injection rates that result from reaching the fouling induced downhole tubing pressure limit in CCS#2. Regarding the other monitoring zones, only modest changes in pressure are observed. No significant changes in the zonal temperatures are observed. These figures also illustrate the unstable operation of the Zone 3 gauges. The gauges raw (discrete) data was extracted and subjected to extensive filtering to remove any null value. Even with these values removed, one can see variation in the temperature not observed in the other instruments. As discussed previously, we are examining options to mitigate any reduction or loss of data and maintain the fidelity of our monitoring system. Figure 20 and Figure 21 show the downhole pressure and temperature for the two Mt. Simon monitoring zones in VW#1. From these figures, a modest increase in injection zone (Zone 2a and 2b) reservoir pressure (25 psia) is seen during the monitoring period, while no change in reservoir temperature is evident.

Figure 22 shows the downhole pressure and temperature for CCS#1. From this figure, one observes greater fluctuations in reservoir pressure (Mt. Simon A – Lower unit) not observed in the other monitoring wells. Despite this artifact, the overall pressure response generally trends with the other Zone 1 gauges. Figure 23 compares the CCS#1 pressure with the zonal pressures observed in VW#1 and VW#2. CCS#1 is almost 3,600 ft from CCS#2 while VW#1 and VW#2 are only 2,700 ft and 2,600 ft respectively. Because pressure attenuates as a logarithmic function with respect to the distance from the source, one would expect a decreasing pressure gradient as you move further away from the CCS#2. This behavior is not observed in Figure 23 where CCS#1 has a significantly higher-pressure response when compared to the closer monitoring wells (VW#1 & VW#2). As previously mentioned, this seems to indicate that proximate to CCS#1, the pressure is being transmitted from the Mt. Simon A Upper (injection interval) to the Mt. Simon A Lower.

Figure 24 compares the CCS#1 pressure response against the CCS#2 injection pressure. From this figure, one can see that the CCS#1 pressure response trends the 96 hours (4 days) moving average of the CCS#2 injection pressure. When compared to historical trends, this effect is significantly less pronounced at the currently lower CCS#2 injection rates. This indicates that the injection pressure from CCS#2 is readily transmitted to CCS#1 with a four-day lag. The following discussion is provided to explain the pressure response observed within this unit.

As previously reported in the site's core and petrophysical logging data, a thin impermeable (mudstone) layer separates these two geologic units and retards the pressure transmission between the injection interval and the lower units. This layer is extremely thin having a thickness measured in inches and was thought to be extensive at our site. But a review of the petrophysical logs reveal some differences that indicate this layer may not exist proximate to CCS#1. Figure 25 shows the site's petrophysical data acquired from the well logs. This figure details the position of the mudstone layer at each well location. Reviewing the CCS#2, VW#1, and VW#2 data, a sharp decrease (spike) in permeability is seen and this feature helps defines the existence and position of this layer. This permeability artifact is not apparent in the CCS#1 well data. This indicates that the layer is pinching out creating an area of greater vertical permeability proximate to the CCS#1 well bore. As the pressure flux develops in the Upper Mt. Simon A, these areas of higher vertical permeability allow localized pressure transmission to the Lower Mt. Simon A producing a localized pressure flux within this unit. This would explain the Lower Mt. Simon A pressure monitoring data that shows the development of a localized pressure gradient at CCS#1 that corresponds to the pressure gradient in the injection zone (Mt. Simon A – Upper Unit). Several other factors, not mentioned above, may also be contributing to the pressure effect observed in CCS#1. The project's geotechnical team has reviewed the data and recommended additional changes to the site's static geologic (Petrel) model to account for these observations. The updated 2018 model included these changes, but further evaluation of the site data may be needed to better understand this effect.

Figure 26 delineates the MESPOP (pressure front = 62.2 psi) predicted by the original 2016 Eclipse model as well as the updated 2018 Eclipse model. From this figure, one observes that the 2016 model's pressure front area is about 100% greater than the pressure front predicted by the updated 2018 model. Several factors account for this change and will not be reviewed in this report. Please refer to *Technical_Report_Ref_CS1903-001-SYL.pdf* submitted as supplemental information in the CCS#2 semi-annual report #26. The current pressure front extends approximately 10,930 feet from the injection well and covers an area of approximately 375 million square feet.

***Discussion of Results – Plume Tracking***

During the reporting period, no geophysical monitoring (pulsed neutron or surface seismic) was conducted to monitor the movement of the $CO_2$ plume. However, during the reporting period, reservoir fluid samples were taken from the injection horizon at VW#2 - Zone 2 to help determine when $CO_2$ arrives at this monitoring point. The last reservoir fluid sample with no detectable $CO_2$ was acquired on February 26, 2019. However, when the well was sampled on September 22, 2020, the sample was saturated with $CO_2$ confirming the arrival of free phase $CO_2$ at this monitoring point. The arrival of $CO_2$ at this well aligns with the current reservoir model forecast. Figure 27 delineates the current and final position of the plume front and as predicted by the 2018 Eclipse model. The current plume front has an area of 35.9 million $ft^2$ with an estimated boundary extending about 3,500 ft from the injection well. The figure also shows that the plume front has passed VW#2. Using the updated model, the plume front passed VW#2 after injecting approximately 1.8 million Mt of $CO_2$.

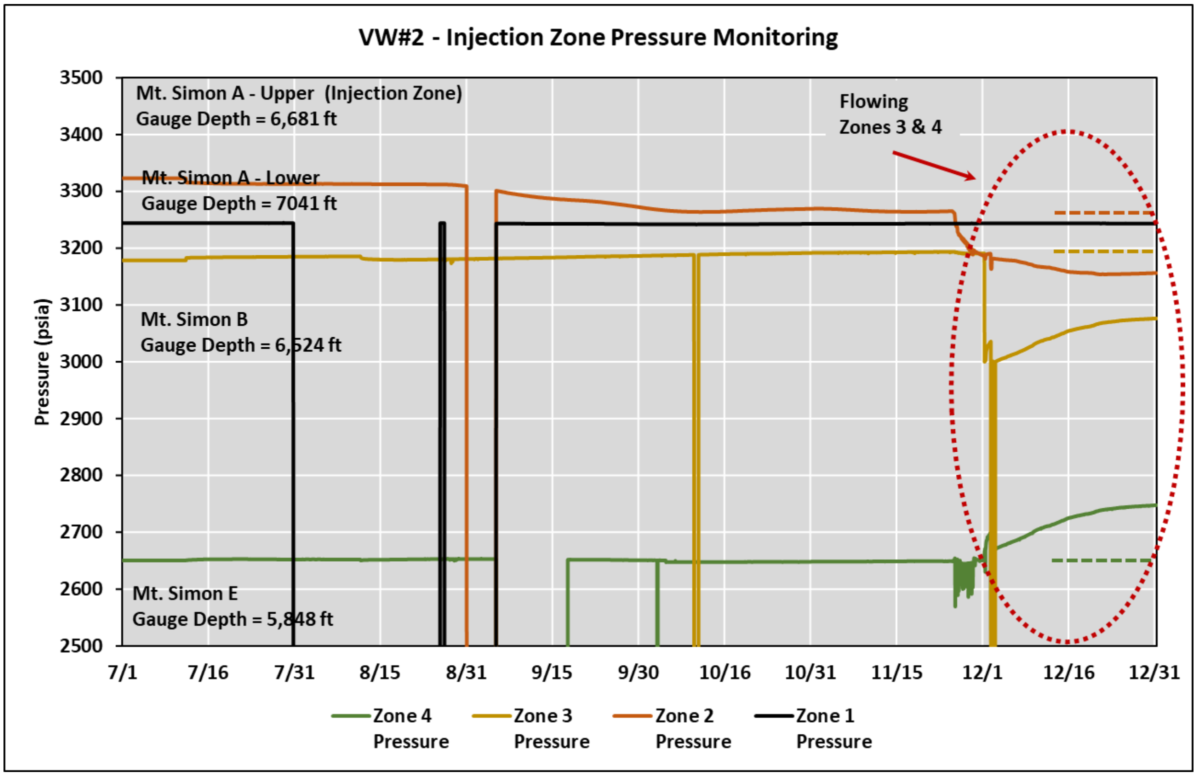


**Figure 18:** VW#2 injection zone pressure monitoring data for Jul-Dec 2021.

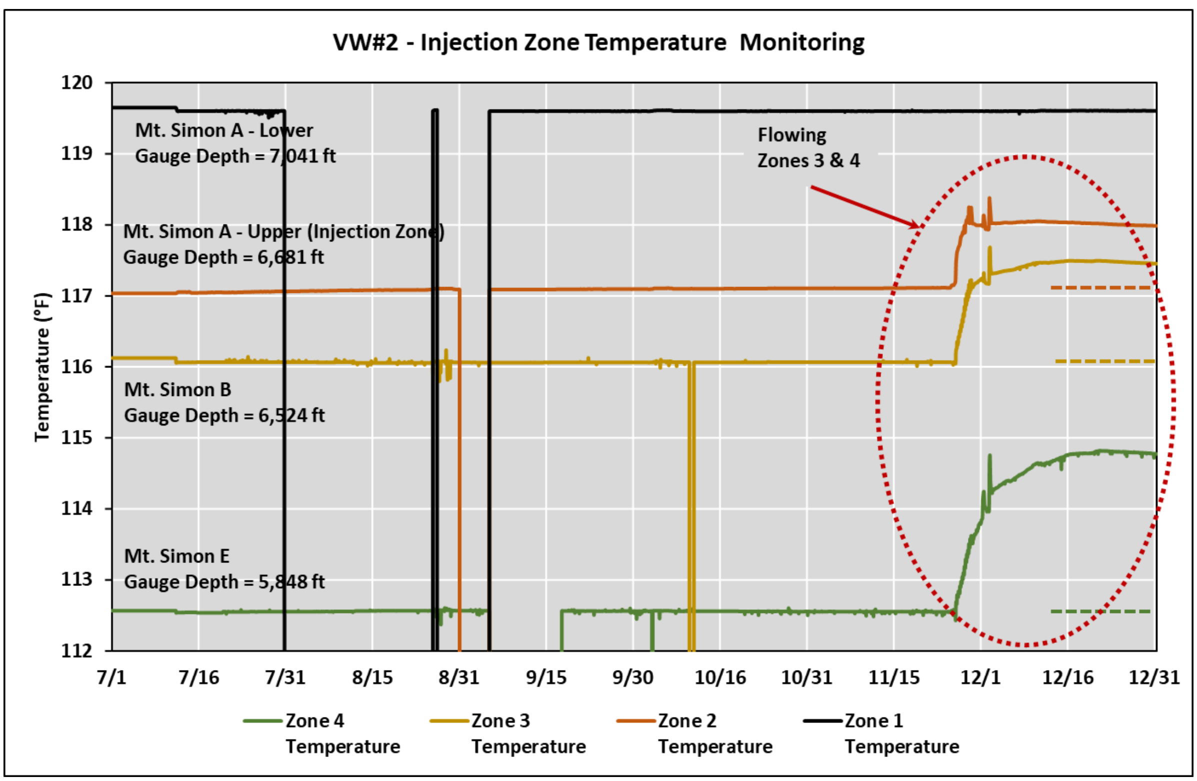


**Figure 19:** VW#2 injection zone temperature monitoring data for Jul-Dec 2021.

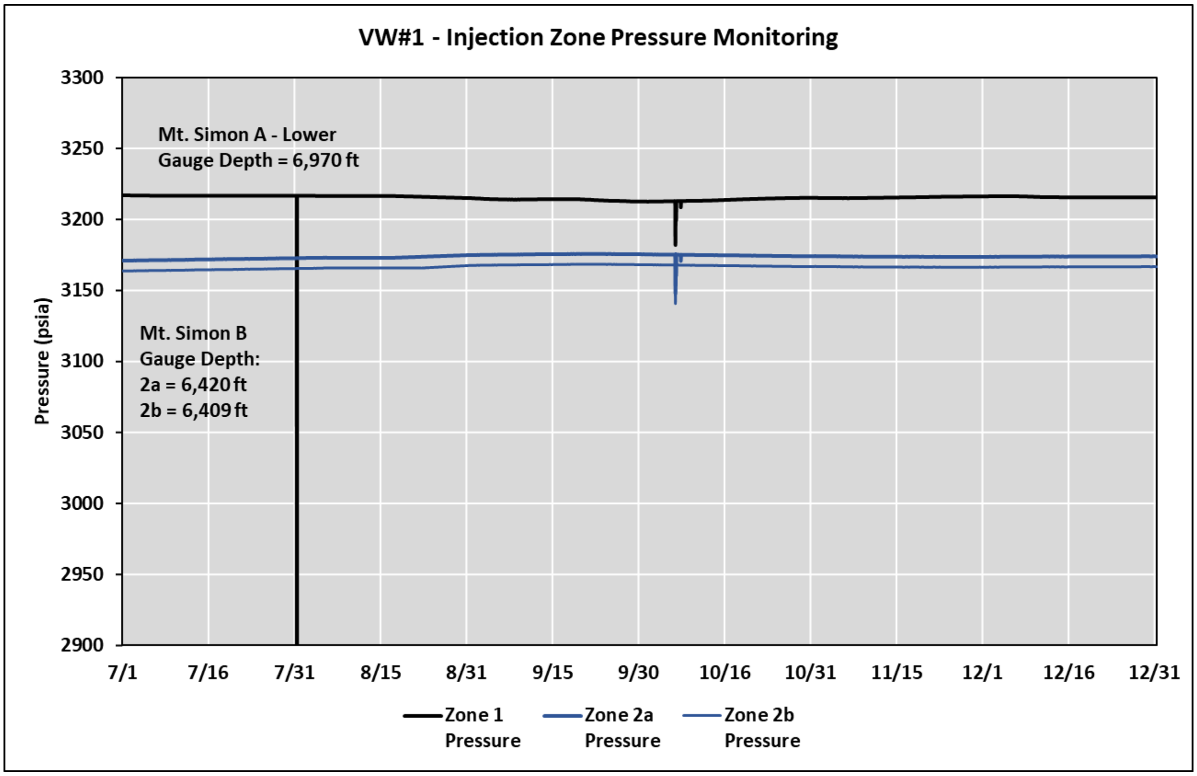


**Figure 20:** VW#1 injection zone pressure monitoring data for Jul-Dec 2021.

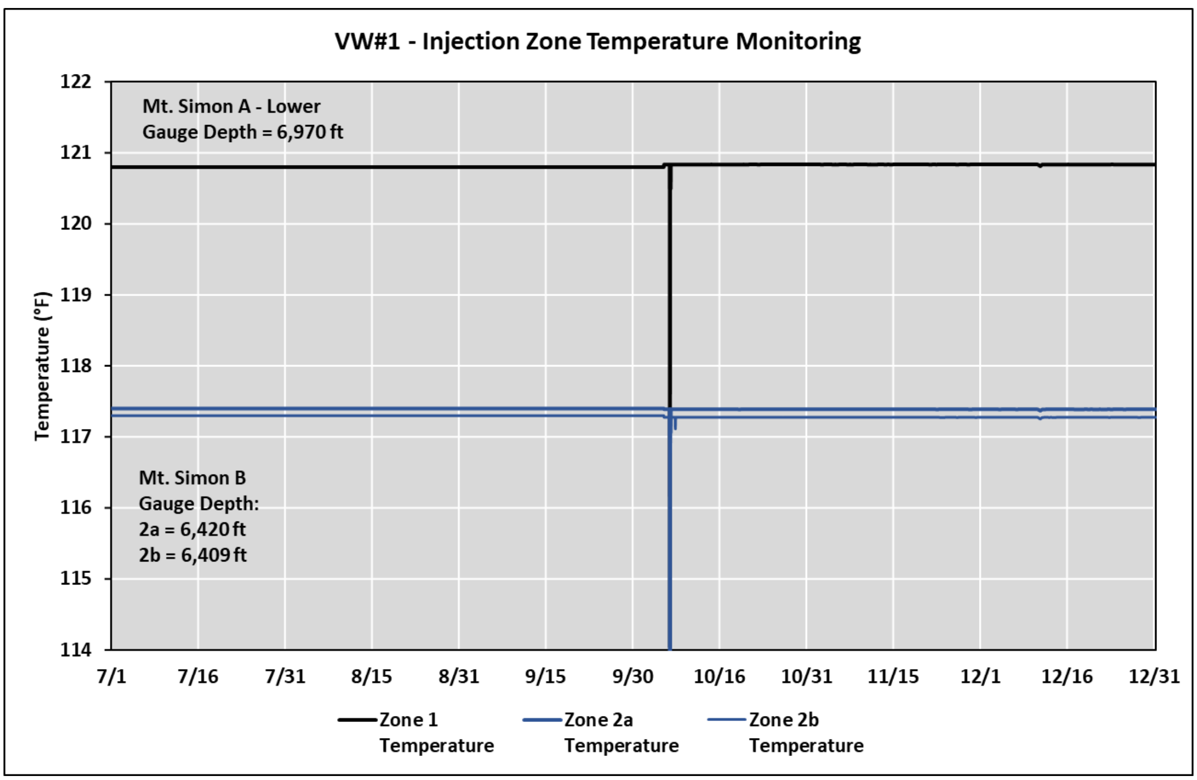


**Figure 21:** VW#1 injection zone temperature monitoring data for Jul-Dec 2021.

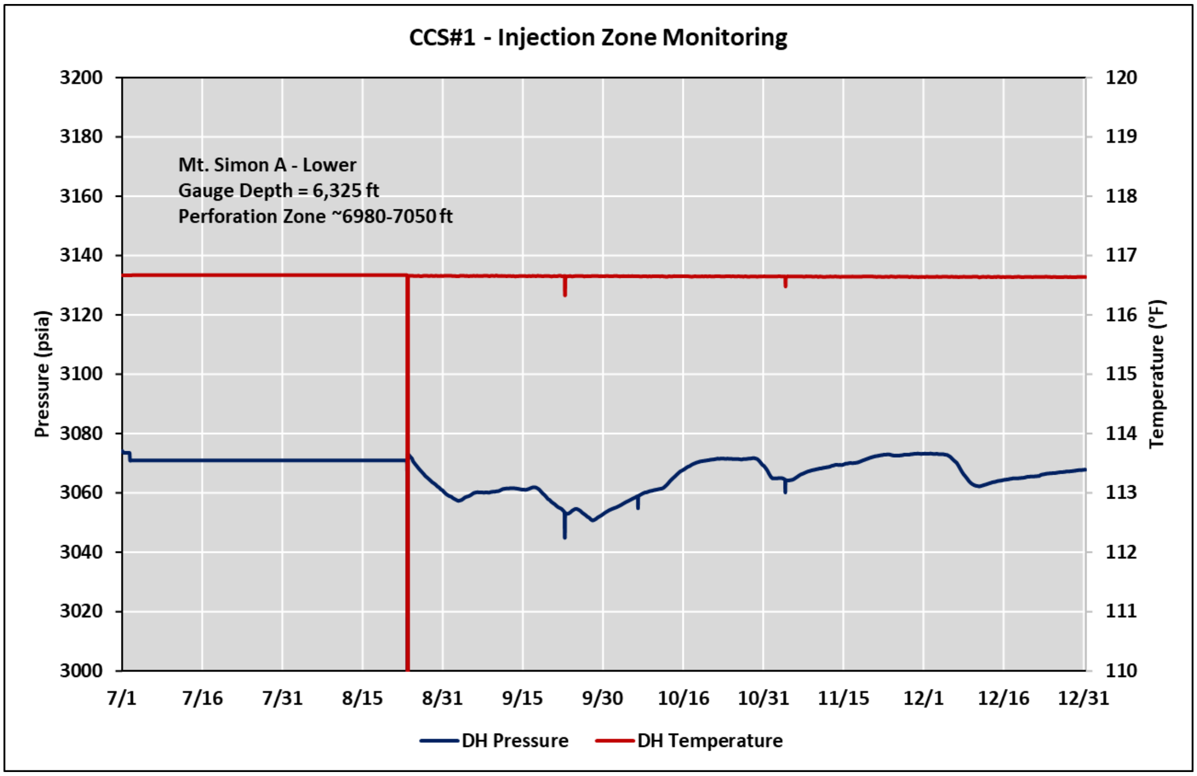


**Figure 22:** CCS#1 injection zone temperature & pressure monitoring data for Jul-Dec 2021.

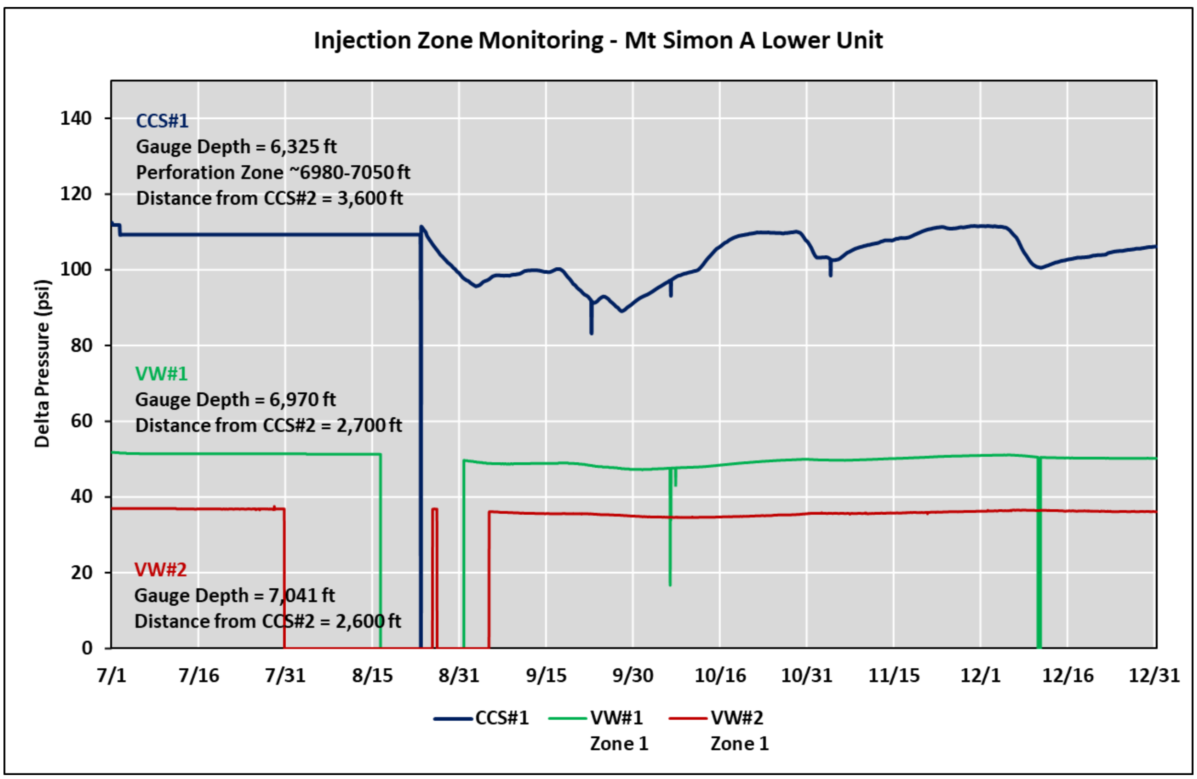


**Figure 23:** Comparison of the pressure change in the Mt. Simon A Lower at CCS#1, VW#1, and VW#2.

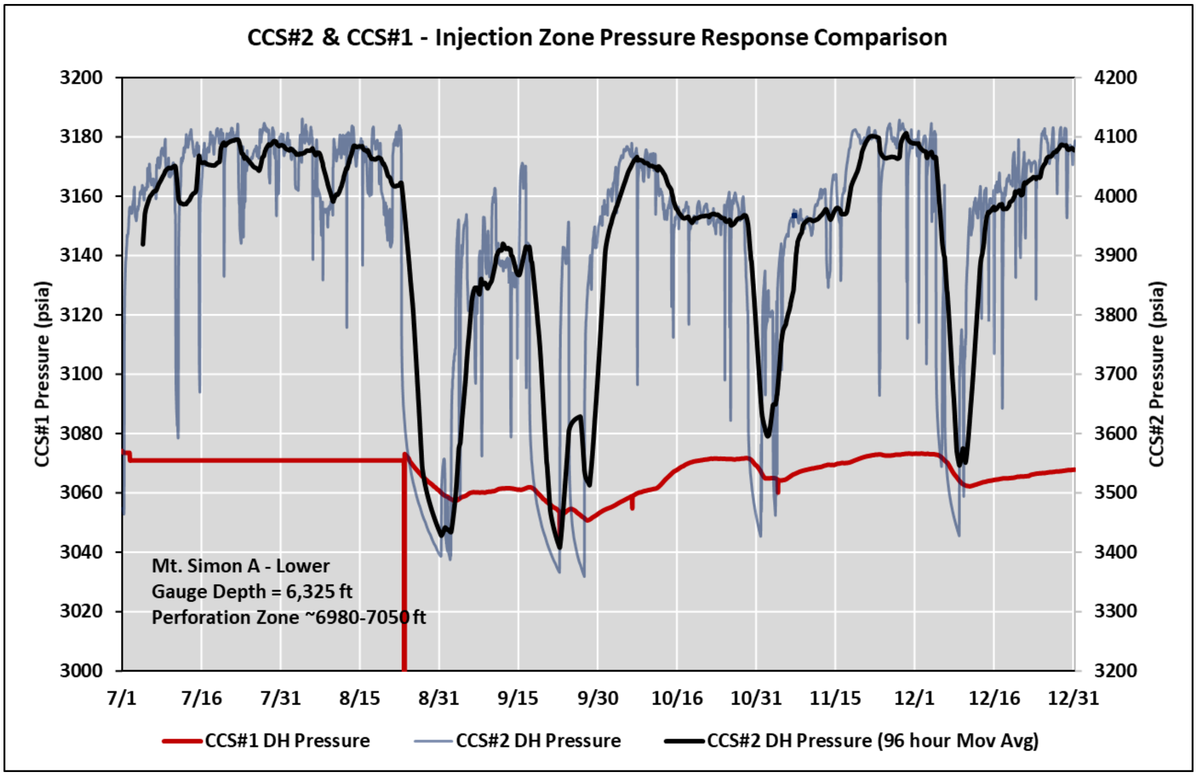


**Figure 24:** Comparison of the CCS#1 pressure response to CCS#2 injection pressure.

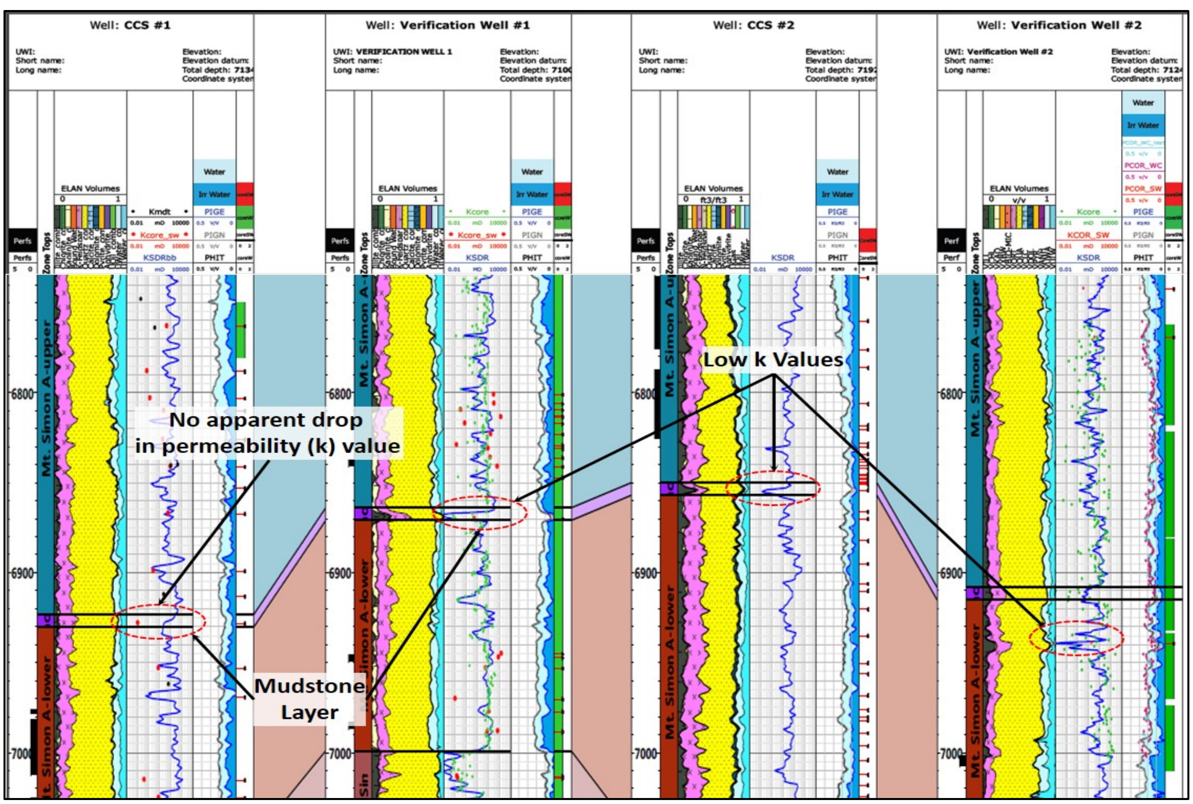


**Figure 25:** Geophysical logs detailing the location and properties of the mudstone layer separating the Upper Mt. Simon A from the Lower Mt. Simon A.

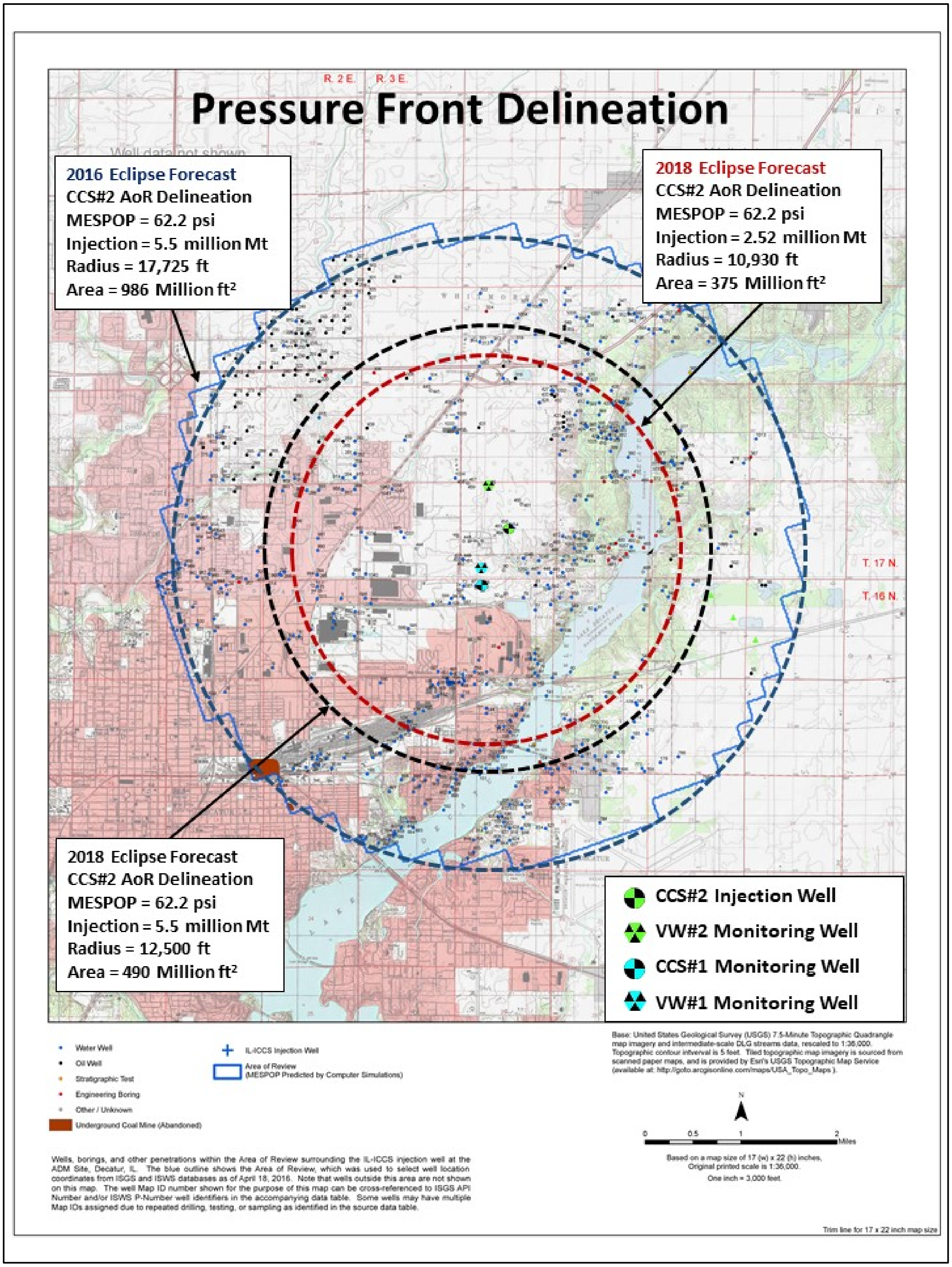


**Figure 26:** Pressure front delineation of the 2018 Eclipse model versus the 2016 Eclipse model.

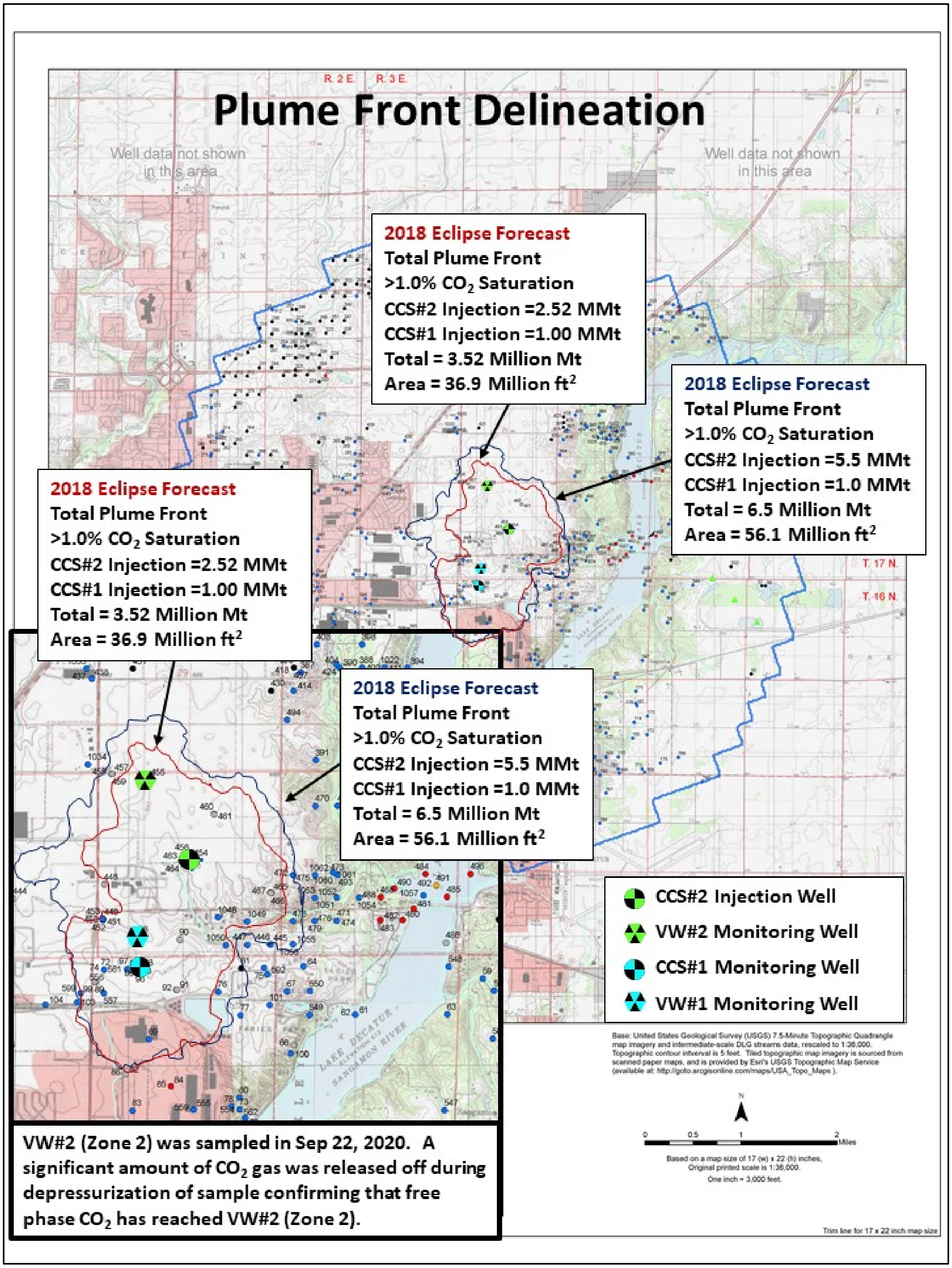


**Figure 27:** 2018 Eclipse model's plume front delineation for December 31, 2021 and after the total injection of 6.5 million Mt (CCS#1=1.0 million Mt and CCS#2=5.5 million Mt).

***Supplemental Material***
No supplemental information to be provided.

## 10. Other Testing and Monitoring

On April 7, 2021, the CCS#2 down hole pressure and temperature gauges were checked against a calibrated set of retrievable temperature and pressure gauges. The downhole gauges were within tolerance and the results were submitted in the CCS#2 Semi-Annual Report 28 submitted as supplemental information.

***Other Supplemental Materials***

| | |
|---|---|
| VW#2 Zone 5 Pressure Monitoring: | ***20210818 MOC VW#2 Tubing Pressure Mod*** |
| Pulse Neutron Logging Letter: | ***20211213_USEPA_Permits_IL-115-6A-001_and_IL-115-6A-0002_Notification_Rescheduled_ Pulse_Neutron_Logging*** |